THE GEORGES BANK PETROLEUM STUDY

Volume I

Impact on New England Real Income of Hypothetical Regional Petroleum Developments

by

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Acknowledgements

This is Volume I of a three volume report studying the implications of a petroleum development on the New England continental shelf. Volume I examines the impact on regional income, Volume II, the impact on environmental quality, and a Summary volume integrates and summarizes the results. We emphasize that Volumes I and II cannot be read independently of each other. In particular, Chapters I.6 and I.7 of this volume depend on results developed in Volume II. The study was sponsored by the National Sea Grant Program, the New England Regional Commission, and New England River Basin Commission. More complete acknowledgements will be found in the preface to the Summary.

This report is a joint effort for which the Offshore Taskgroup is collectively responsible. However, Prof. J. Devanney had primary responsibility for Chapters I.1, and I.3 through I.8 assisted by Prof. M. Adelman, Prof. A. Wright (Chapter I.3) and Mr. Jack Price (Chapter I.6). Chapter I.2 was the primary responsibility of Prof. Joseph Lassiter who developed the offshore model with the assistance of Mr. Nathaniel Ng. Mr. H. S. Lahman has responsibility for the overall development and programming of the Petroleum Development Simulation program. Assistance on the refinery model was contributed by Prof. E. Gilliland and Mr. C. Reed.

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I.1.1 Some ground rules

This study is an attempt to aid New England's decision-makers in determining what should be the region's response to the possibility of a petroleum discovery on the New England continental shelf through the application of some very specific quantitative techniques to some of the issues raised by this possibility. Before we begin, it is important to understand what this study does not attempt to do.

It does not attempt to tell the region's decision-makers what their decision should be. Rather, it attempts to determine the implications of each of a number of possible developments ranging from no change in the present system to very sweeping shifts in petroleum production source, crude transport system, processing location, and product distribution system. The fact that we analyze a particular development does not imply that we hold any brief for or against this alternative. All our statements will be of the "if the region does 'such and such', then this is our best estimate of what will happen" variety without making any judgement of whether or not this means that the region should do 'such and such'.

Further, we have chosen to operate with a precisely circumscribed view of what we mean by the "implications" of a proposed development. In this volume of the report, by implications we mean the net effect on real regional income - a concept which we will define at some length in the next section. However, briefly this concept relates to the region's economic well-being as a whole and takes no cognizance of intraregional transfers of income either across intraregional political boundaries or across income classes. In the second volume of the report, "implications" is defined to be the change in regional water and air quality and the presently identifiable effects these changes will have on the biota.

Implications of potential petroleum developments which are not addressed in this study include the impact on the political structure of the region and the functioning of its legislative process, and the impact on psychological and aesthetic values associated with industrialization and urbanization which are not reflected in the market process or directly tied to water and air quality.

Our reason for limiting ourselves to this circumscribed set of implications is not that we believe these other values are unimportant but rather that this self-limited set of values represents the boundaries of useful quantitative analysis to which we claim special expertise.* We believe that adhering to these limitations will increase rather than decrease the usefulness of the study to the region's decisionmakers.

The report will make no attempt to assess the likelihood that a certain amount of oil and gas will be found, nor its exact location. Such an attempt without access to the seismic data already taken would be severely and unnecessarily handicapped. Further, even if the seismic data is made available to the region, a wide range of possibilities will still exist. Rather, we have taken the tack of hypothesizing a spectrum of possible geologies ranging from no discovery to a discovery so large that it is extremely unlikely to be exceeded and for each of these hypothetical possibilities analyzing the implications for

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*Actually, a useful quantitative analysis of the effect on subregional income, say that of the state of Maine, could be undertaken. The extensive, but far from complete, commonality of interests within the six states dictated our particular choice of political boundaries. Also, it is probably the case that the region is the smallest political entity which can have any significant effect on federal policy with respect to New England petroleum.

regional income and environmental quality. Thus, in analyzing a particular geology we are not implying anything about its likelihood, only that it is possible. As we shall see, we can make many important statements independently of the exact nature of the find. We will, however, take advantage of one set of geological facts. Sediment depths on the New England continental shelf west of a line running roughly from Cape Sable to the outer edge of Nantucket Shoals and southwest to the slope are so shallow as to make this area an extremely unlikely prospect for petroleum. Thus, all our hypothetical discoveries are assumed to be located to the east of this line on Georges Bank proper.

Finally, a word about style. The purposes of this report will be realized only if it is understandable to the general public. Therefore, we have attempted to avoid technical and special-purpose words and phrasing as much as possible. However, from time to time we shall be forced to define and use technical terms. We bring the point up so that the general reader realizes that, whenever we are forced to use a technical phrase, it is done so reluctantly and only because there is simply no usable counterpart in the common language. This is usually because of the connotations associated with possible substitutes. Unfortunately, these specially defined words often also have a meaning in common usage - a meaning different from that which we desire to use. Thus, one must take careful note of these definitions, when they occur, and remember, as Humpty Dumpty said to Alice in Through the Looking Glass, from that point on, "the word means precisely what we choose it to mean; neither more, nor less."

I.1.2 The concept of regional income

This volume of the report analyzes the effect of a number of hypothetical Georges Bank petroleum developments on the real regional income of New England. In so saying, we have in mind a very precise idea of what we mean by regional income. An understanding of our definition of regional income is absolutely crucial to an understanding of this report. Failure to be precise about what one means by regional income--and a change in regional income--has generated untold hours of unproductive public debate. The two basic goals of this report are (1) to generate the information to make the public discussion concerning offshore oil as informed as possible and (2) to focus this debate along as productive a line as possible. A precise understanding of the concept of regional income is fundamental to both these purposes.

Perhaps the easiest way at getting at our definition of regional income is to imagine that the six-state region is owned and controlled by a single personage - Uncle Eph we might call him. Uncle Eph is interested in the total value, at market prices, of all the things he can consume with the output of the rather extensive resources he controls. Uncle Eph realizes that he can allocate his resources in an infinite variety of ways, some of which will allow him to consume a higher total value of goods than others. Uncle Eph would like to make the market value of his consumption as large as possible.

His resources include not only the land and water, the factories and buildings, vehicles and vessels of New England, but also its human inhabitants. We might regard this latter brand of resource as Uncle Eph's fingers, in that they both produce and consume.

Uncle Eph has no particular feelings about his fingers. He isn't interested in whether one finger or another consumes a greater share of the total value of all the goods he consumes. He is only interested in the total. He considers himself better off if this total value is larger, worse off if it's smaller, regardless of the distribution of production and consumption among his fingers.

We define the total value of the goods, priced at 1972 market prices, which Uncle Eph can consume, to be the real regional income of New England.*

Notice that in attempting to maximize this quantity, Uncle Eph is ignoring the fact that any proposed change in the allocation of his resources will almost certainly make some of his fingers worse off and some better off. Uncle Eph simply doesn't care. He prefers the change if the total value of the consumption of all his fingers is higher after the change than before. He will eschew the change if the total value is less. Our concept of regional income ignores the distributional effects of any proposed change, both geographically within the region and across income classes.

From time to time, we will comment on these effects, but only in passing. The thrust of our efforts in this volume are aimed at determining the effect on the six-state region's (Uncle Eph's) ability to consume and not on the effect on any subset within the region. This limitation has obvious political implications, for what may be a net increase to the region as a whole can affect a particular set of losers quite adversely. For example, real regional income will be increased by a change which

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*The adjective "real" in this context merely implies that our concept of income is based on 1972 prices, which prices are held constant throughout the analysis. Thus, our concept recognizes that a general increase in prices which inflates the market value of Uncle Eph's consumption without changing the composition of the goods actually consumed is not an increase in "real" consumption. Conversely, it recognizes that an increase in amount consumed made possible by a decrease in price is an increase in "real" consumption.

increases the real income of 99% of the region's citizens by 1% and decreases the real income of 1% of the region's population by 70%, virtually wiping out this latter group. This brings up the topic of compensation schemes for the losers which at times, in a digression from our basic philosophy, we will discuss in some detail in the sequel.*

There is another thing to notice about Uncle Eph. His is a provincial and basically selfish character. He only cares about his own ability to consume. He is completely indifferent to any effect, up or down, his choices might have on the income of entities outside the region, the other forty-four states, for example, or the rest of the world. Any change in income to someone who is not a citizen of New England, no matter how large, is given no weight at all by our concept of regional income. Once again, from time to time, we will comment on these extra-regional effects, but only when they are particularly glaring or have important political implications for the region.

In order to implement this parochial philosophy, we shall have to be quite precise about what we mean by a citizen of New England. For the purpose of this report, a citizen of New England is anybody residing in or holding real property in the six-state region <u>before</u> a proposed change takes place. In the case of a non-resident property owner, we count only that portion of his income resulting from his New England real estate. This definition is more than a little arbitrary and at times we shall have considerable difficulty separating out the marginal cases, but of all possible such definitions this appears to be the most useful for the purposes of this particular study.

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*Notice that if a development increases real regional income it is theoretically possible to redivide the enlarged total among the inhabitants in such a manner that every individual's real income is increased.

Notice also that our definition refers to the situation just prior to the proposed development. Thus, any change in the income of people drawn into the region by a development, such as extraregional construction men or oil rig operators, will not be counted. Of course, any net effect this immigration would have on the income of people already in the region will be counted.

Another important point about Uncle Eph is that in deciding to measure his well-being in terms of regional income, he is accepting prevailing market prices as fixed. Thus, if the market says that an apple is twice as valuable as an orange, Uncle Eph regards himself to be in no position to dispute this judgement. Rather, he will adjust his consumption, buying just enough apples and just enough oranges, so that after making these purchases, he is indifferent between an extra apple and two extra oranges. That is, he reacts to market values rather than attempting to set them.

There are two reasons why we have made this extremely important assumption.

a) In reality, most market prices are fixed as far as New England is concerned. Since New England doesn't have the right to set tariffs in its trade with the rest of the world, it would take a completely infeasible and probably illegal amount of regional coordination for the region to have any effect on most prices.

b) Insofar as prevailing prices are set by competition, these prices reflect the relative willingness to pay of the region's inhabitants for the goods so priced. Thus, if one accepts the present income distribution, one can make an argument that these prices are an imperfect but indicative reflection of people's underlying desires. Further, even substantial changes in income distribution are likely to have little effect on most prices.

This argument holds only for those goods for which a functioning market exists. The fact that no market exists in which water quality or air quality or scenic values can be exchanged means that these goods can be severely underpriced in terms of the region's underlying willingness to pay for them. The lack of markets for environmental amenities is one of the reasons why we have devoted an entire, separate volume to these non-market goods. In addition, there are a number of goods for which the market process operates so imperfectly or has been so circumscribed that it would be misleading to regard their prices as representative of the region's willingness to pay and certain adjustments will have to be made. Natural gas is an example. However, these cases will be handled by exception to our basic philosophy in this volume of accepting the market's valuation of the various goods which New England might consume.

The final and in some ways the most important point to make about our decision to measure regional well-being in terms of regional income is that in assessing any two alternative developments, the only thing that counts is the net difference in regional income between the two. This is an obvious statement but one that is frequently ignored in the public debate concerning potential developments.

To see what we are driving at consider what is, in the context of this study, a reasonably neutral example. A region is contemplating the construction of an office building on a particular plot of land which is currently devoted to an intensely cultivated truck farm. The potential developers have determined to their satisfaction that the building is at least as good an investment for their capital as they could make elsewhere. Having done this, they approach the region to convince it that it is in the region's interest to have this project undertaken.

Potential developers usually concentrate on the input side, that is with regard to the resources which will be employed in their proposal. In this case, they note that the building will cost them ten million dollars, of which half will be spent within the region. They point out that the bulk of this five million will be respent within the region" which money will in turn be respent and so on. In this manner, the initial expenditure will be "multiplied". Further, upkeep and maintenance of the building will involve expenditures of $500,000 a year, which expenses are also subject to respending effects. Depending on the multiplier assumed, they conclude that the building will have an effect on the region's economy several and sometimes many times larger than the gross expenditures associated with the project.

Opponents of new developments generally argue on the output side, that is, with regard to the value of the goods the current use of the land produces.* Thus, the opponents of the proposed building point out that the gross revenues of the truck farm are two million dollars a year, most of which goes to the farm's 200 workers who will lose their jobs. They argue that not only will the region's economy lose two million dollars a year directly, but also farm equipment, fertilizer, and seed suppliers and others throughout the region whose livelihood depends on the respending of the farm workers will be adversely affected, starting a multiplier chain. The multipliers assumed by opponents of a development are usually of the same order of magnitude as that of the proponents, the difference being that it is usually applied to the gross value of the

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*In reality, both opponents and proponents of new developments often mix input side and output side arguments. However, we can make our point using the above simplification without loss in generality since, as we shall see, the same basic principles refer to both lines of reasoning.

outputs of the present use of the site rather than the gross value of the inputs.*

Both sides are making a basic error in talking gross, not net, changes. Assuming that the developers' and opponents' underlying figures are correct, let's examine this decision about resource allocation from the point of view of our concept of regional income. That is, let's attempt to determine the difference in real regional income as defined earlier between constructing the office building and leaving the site as a truck farm. Start with the developers' five million dollars to be spent within the region. For simplicity's sake, assume this all goes to construction labor. The first question we have to ask ourselves is what would this labor be producing if it weren't employed on this building. The market value of this alternative production measures the cost to the region--as opposed to the cost to the developer--of using this resource on the building.** If there is nothing else this labor could be doing, obviously the alternative opportunity value of the labor is nothing. The transfer of the labor to this project involves no loss in regional production elsewhere and hence the cost to the region of employing the labor on the building is zero. In this case, the full five million dollar payroll represents a net increase in regional income, as is evidenced by the increase in the pay the construction workers actually take home. But, if the construction workers could be employed elsewhere producing something else whose value approximates the wage rate--the situation when we have full employment--then the cost to the region of diverting this labor to the proposed

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*It really doesn't make much difference, for assuming normal profit levels, the gross expenses of any undertaking will be approximately equal to the gross revenues.

**To see this, look at it from Uncle Eph's point of view.

building is the loss in output elsewhere.* Under full employment this loss would be about five million dollars and the payroll in itself generates no increase in regional income as is evidenced by the fact that whether the construction worker works on this particular building or somewhere else, his paycheck is unchanged. In the case of full employment the cost to the developer of the labor, five million dollars, and the cost to the region are approximately equal. In this situation, the net increase in regional income due to the construction payroll is zero.

The net effect on regional income of expenditures on inputs depends critically on the alternative opportunities for employment which these resources have. This crucially important principle is rarely emphasized in the public debate concerning proposed developments. It applies to all inputs, land, capital, materials as well as labor. For any such input, the direct effect of its purchase on regional income can range from the full expenditure, if there is complete unemployment of that resource, to zero if full employment, and indeed can even be negative if the market price of the input is lower than the market value of its output.**

However, in applying this principle we will concentrate on the input, labor. The reason for this is that it is ordinarily difficult for the market price of land or

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*Full employment means no excess supply of labor, which in turn implies that regional employers find that the wage rate is low enough so that the market value of what each laborer produces is at least as great as the wage rate. Therefore, under full employment, the market price of labor is no higher than the value of what that labor can produce.

**This happens when a good is priced at less than the opportunity value of its use to the region due to regulatory control (natural gas, foreign currency) or the lack of a market (air and water quality). Such a situation is known as rationing for at the market price the supply of the good will be less than the demand. Rationing (a shortage) is the opposite of unemployment (a surplus).

capital or natural resources to rise much above their opportunity value for a variety of reasons: mobility, antitrust legislation, ability to be stored, etc. But the input labor is often in partial unemployment, that is, the opportunity value of labor is often somewhat less than the market price, though rarely is it a great deal less. Setting the wage rate too high above opportunity cost generates unemployment, which generates people willing to work for less than the prevailing wage, which willingness puts a limit on how far above the opportunity cost of labor the wage rate can rise. We will later offer evidence that even in the present situation facing New England (7% unemployed), average regional wage rates are less than 20% above the alternative opportunity value of the labor, in which case the direct effect of the five million dollar expenditure on regional income is one million.

Now let's turn to the multiplier. Obviously if we have full employment and there is no change in construction workers' income with and without the building then the net effect on regional income of the multiplier effect is zero, since there is no difference to multiply. But let's say we are facing a partial unemployment situation such that the direct effect on construction workers' take-home is 20% of the gross payroll or one million dollars. Then we can properly apply a multiplier <u>to this difference</u>, for there will be a difference in the workers' expenditures.

However, in so doing we must once again be careful to obtain the <u>net effect</u> of this additional respending on regional income. Let's suppose that as a result of his increase in income, the construction worker spends an additional five dollars a week on, say, clothing. The clothing retailer sees an increase in his gross revenues of five dollars. Does that mean there is a net increase in regional income of that amount? Obviously not. The worker's expenditures require the employment of certain resources: the retailer's help, the labor, and capital required to manufacture the apparel and bring it to market. Even if all these resources are intraregional, the cost to the region is again the alternative opportunity value of these resources - the value of what they could be producing if employed elsewhere. It is true that, due to fluctuations in demand, service industries tend to operate at less than capacity much of the time. Thus, if the worker happens to spend his extra clothes money at a time when retail capacity is in oversupply, then the additional cost to the store owner and to the region of selling these additional items is little more than the wholesale cost of the clothes. The rest is profit and this, less the bulk of extraregional taxes, is a true increase in regional income due to the increase in the store owner's net income. If, on the other hand, the money is spent during the Christmas rush, then either the store owner will be forced to hire additional help or the quality of service to the rest of his customers will decrease (they will bear some of the cost). If retail capacity was correctly set before the increase, the store owner will find that his net income has increased very little as a result of the additional expenditures.* In short, the same kind of partial unemployment we find in the direct labor markets we also find in the markets in which respending occurs. The net increase due to first-round respending is some percentage of the actual expenditures, which percentage depends on (a) the amount of regional input to the good or service, and (b) the degree of unemployment in the regional respending market. For most respending markets, 20% would be a

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*Or the store owner may respond to the increased demand by raising prices, which will have no net effect on regional income, for the increase in real income of the seller will be matched by a decrease in real income of the buyer.

generous estimate of the net increase in regional income. Obviously the same kind of argument holds for the second round of respending (the store owner's additional purchases of clothing and help) and so on ad infinitum, except that if full employment obtains in any of these markets or all the resources used are extraregional then the chain is broken and the increases in regional income stop at this point.

For the sake of argument, let us assume that the chain is never broken, that goods in all markets are priced at 20% more than their opportunity cost of their inputs to the region. What is the net effect of this entire multiplier chain on regional income? It is $1 million (first round 20% of $5 million) plus $200,000 (second round 20% of $1 million) plus $40,000 (third round) plus $8,000 (fourth round) and so on. One can show that if one adds up these rapidly decreasing amounts for as many rounds as one wishes to consider, the total approaches $1.25 million or 25% of the original $5 million payroll. In short, the <u>net</u> effect of the multiplier phenomenon on regional income is generally much overstated. Moreover, its influence drops off rapidly in two or three rounds. In Chapter I.5 we will study these multiplier effects in some detail for the specific development hypotheses we have in mind. We shall find in certain instances they can be locally substantial if a pocket of severe unemployment is specifically attacked by a project but that in entire regional income terms they are rarely anywhere near as striking as commonly claimed. Of course, we knew this. If the multipliers of three and five that developers often claim actually affected net regional income by that amount, then we would have invented the money tree. By simply undertaking more and more expenditures, we could increase regional income indefinitely. The developers' arguments are based on the implicit assumption that the resources used by their project cannot be used in any other way.* This is rarely, if ever, the case.

The arguments against the proposed building must be examined from the same point of view: what is the difference in regional income? It is true, of course, that if the office building is constructed the region will lose the output of the truck farm and the farm's total revenue is the gross market value of this loss. Does this mean that regional income will decrease by this amount? Not necessarily, for as the opponents themselves have pointed out, if the farm goes, several other things will happen as well. First of all, 200 farm workers will lose their jobs. This means that 200 more people are now available for employment elsewhere. If we have a full employment situation, they will, after a time, find employment elsewhere at wages (producing output whose value is) approximately what they were earning and the net effect on regional income due to the job loss will only be the difference in their pay during the transition period plus any net multiplier effect on this difference. Similarly, the land will find employment elsewhere as building space and obviously the owners of the truck farm will not sell the land unless they feel they are at least as well off after the transaction as before.

In short, from the gross loss in output, we must subtract the value of what the farm's workers will produce elsewhere, the resale value of the farm's equipment, and the payments to the farm's owners for the land to obtain the direct loss in regional income associated with the

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*More precisely, we must distinguish between the gross multiplier--the total amount of economic activity required to support a specified investment--and the net multiplier effect, which deducts from this total the value of the output of these resources in alternative employment. It is the latter concept which is relevant to regional income discussions.

demise of the truck farm. In a perfectly competitive economy, this difference would be zero, both the landowner and the truck farm labor being indifferent to the change. In actual fact, it's rarely zero; ordinarily the displaced labor will suffer a real loss in income at least during a transition period and the landowner will experience a gain. The net effect can be either positive or negative but it rarely approaches anything like the gross value of the former output.

To this difference, we must apply a multiplier to account for partial unemployment elsewhere in the economy, but exactly the same line of reasoning holds for this multiplier effect as for the multiplier effects due to changes in construction worker take-home pay. That is, the indirect change in regional income is a fraction applied to a fraction of the gross value of the output of the truck farm.

In short, the same kind of "let's look at the difference" viewpoint applies to the present use of the resources as well as the proposed new development, and the same kind of differential magnitudes obtain. Our concentration on the <u>net</u> effects on regional income of a proposed change is a two-edged sword biting deeply into <u>both</u> the usual "economic" arguments for development as well as the "economic" arguments against.

When one takes this differential point of view in analyzing two alternative allocations of some resource, attention necessarily becomes focused on those areas where the real changes in net regional income generally reside, rather than on the gross expenditure or gross revenues associated with the various alternatives. These areas are:

1) the difference in the cost of the outputs to regional consumers, e.g. the effect on market

prices (this category applies to two different developments which supply the same good to the region),

2) the difference in private profits to the regional investors affected,

3) the difference in public profits (tax revenues minus additional cost of services occasioned by the developments under consideration) to the regional public bodies affected,

4) the difference in take-home pay to all the regional labor affected,

5) the net effect due to respending of all the above differences.

Notice that, when considering two alternative uses of a resource, items (4) and (5) generally are counterbalancing in the sense that if there is full employment, there will be little difference in take-home pay of the labor involved in either alternative and hence very little net multiplier effect. On the other hand, if there is extensive unemployment, then there may be a sizable difference in take-home pay for the two sets of laborers, but it will be a sizable difference for the laborers involved in <u>both</u> alternatives. If we build the office, the truck farm labor suffers a sizable loss; if we keep the farm, construction labor suffers a sizable loss. The two individual losses may be substantial and the net effect on regional income, their difference, still be small. The same is true of the multiplier effect. With extensive unemployment, it may be considerable for <u>both</u> the proposed development and its alternative, but those two effects have to be subtracted to obtain the net effect on regional income. It's only when

a) there is substantial unemployment which is actually reached by the development, and

b) one alternative employs little or no labor resources and the other a lot

that differences in regional income due to changes in labor income and respending become noticeable on net.

Of course, this cancellation phenomenon is not going to mollify either the farm workers or the construction unions, who will continue to lobby vigorously for their respective options, since they, unlike Uncle Eph, are quite concerned about which fingers do the consuming. The point is that this activity, however vociferous, does not necessarily imply that any regional income is at stake.

I.1.3 The various meanings of the word "cost"

We have already violated our self-imposed precept to use no technical words without first defining them. The word we have in mind is cost.

The cost of an option is the loss in real income associated with that option to the decisionmaker in question. It is the value in real income terms to the decisionmaker of the opportunities forgone if he undertakes this option.

Notice that our definition of cost depends on the decisionmaker involved.* In this report, we shall from time to time be involved with three different decisionmakers:

1) the private investor: the cost to him of a particular investment is all the outlays he must make in order to undertake the investment.

2) the region: the cost to the region of a particular investment is the loss in real regional income which results from diverting regional resources to this project.

3) the nation: the cost to the nation is the loss in real national income associated with the national resources devoted to the project.**

We have already seen how, given unemployment, the cost to the investor and the cost to the region can vary. These costs can also differ as the result of taxation. Regional

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*Our definition also depends on the particular decision under analysis. For example, if the decision is the private investor's choice of whether or not to pursue production drilling once the expenditures for exploratory drilling have already been made, these exploratory expenditures are not a cost of the production drilling decision. They were, of course, a cost of the decision of whether or not to pursue exploratory drilling.

**Although we have no direct interest in national income in this study, the estimation of the national cost of our hypothetical developments turns out to be an unavoidable step toward obtaining estimates of regional cost.

taxes are a cost to the investor but insofar as they are not matched by an increase in cost of regional public services associated with the investment in question, they are not a cost to the region. Similarly, cost concepts (2) and (3) can be different. If a New Englander were to make offshore lease payments to the federal government in order to develop a find, this would be a cost to both the investor and the region but not to the nation.

In short, throughout our analyses we will generally be keeping three distinct accounts, those relating to the investor's income, the region's income, and the nation's income. Whenever we use the word cost, which will be often, we shall have to specify either explicitly or by context to which of these accounts we are referring. In helping us do this, we will use the phrases investor's cost (gross loss in investor income), regional cost (gross loss in regional income), and national cost (gross loss in national income). The reader should pay careful attention to these adjectives when they occur as they are almost always critical to the argument.

I.1.4 An introduction to present value

At this point we must digress from our basic line of thought in order to face squarely the problem that the increases in regional income due to various alternative petroleum developments will in general occur at varying points in time ranging from immediately to perhaps 50 years in the future.

Uncle Eph is a shrewd old New Englander. He realizes that there is considerable difference between receiving one dollar in additional income now and one dollar in additional income say ten full years from now. The reason, of course, is that Uncle Eph has the opportunity to invest the one dollar received now at some annual interest rate, say 10%. After one year so invested, Uncle Eph will have $1.10, which he can reinvest for a second year, obtaining an additional 10% on $1.10 or 11¢, for a total of $1.21, which he can reinvest and so on. If he invests the dollar received now for ten years at 10%, he will find that at the end of the tenth year, his investment will be worth $2.59, which is quite different from one dollar. The timing with which he receives the same amount of additional regional income obviously makes a great deal of difference to Uncle Eph.

To put it another way, if Uncle Eph has investment opportunities which can earn him 10% per year, receiving one dollar now is equivalent to receiving $2.59 ten years from now. He would be indifferent between receiving one dollar now and $2.59 ten years from now but he would certainly not be indifferent between receiving one dollar now and one dollar ten years from now.

Uncle Eph, therefore, realizes he has to put increases in regional income received at varying points in time on a common temporal basis. He chooses to relate them to an equivalent amount received now (1972). That is, in valuing an increase of one dollar which will occur ten years from now, he asks himself what is the amount received now which will grow to one dollar ten years from now. Mathematically we are asking:

What number x 2.59 = 1.00?

The number we are after is simply 1.00/2.59 or 38.6¢. This number is called the present value of a sum $1.00 received ten years from now assuming a 10% interest rate. In general, the present value of a sum x_n received n years from now at an interest rate i is

$$\frac{x_n}{(1+i)^n}$$

If we are dealing with a development alternative which will increase regional income by x_1 in year 1, x_2 in year 2, and so on through N years, then the present value of all these increases, V, is simply the sum of the present values of each yearly increase or

$$V = \frac{x_1}{(1+i)} + \frac{x_2}{(1+i)^2} + \frac{x_3}{(1+i)^3} + \dots \frac{x_N}{(1+i)^N}$$

Uncle Eph reasons that, given his opportunity to reinvest at an interest rate i, he would be just as well off in terms of his real wealth, if he received the sum V now as if he received the entire stream of future increases in income resulting from the development alternative. Thus, in comparing various development alternatives, he will do so on the basis of their present values, that is, on the basis of an equivalent amount of income received in 1972.

The justification for applying Uncle Eph's reasoning to our valuations of New England's alternatives with respect to petroleum is that like Uncle Eph, the region's inhabitants have the opportunity to reinvest their income at some interest rate, say 10%. Insofar as they choose not to reinvest, they are making a clear statement that they prefer one dollar's worth of consumption now to a dollar and ten cent's worth of consumption a year from now. The existence of an interest rate reflects the value people put on consumption now rather than later. Our use of present value attempts to account for these feelings.

Present value also applies to business transactions, and it also implicitly incorporates what would ordinarily be called "normal profit". That is, a firm which has the opportunity to invest its equity capital at 10% has an opportunity the revenues of which exceed outlays through time in such a manner that the "profit" is equivalent to the "profit" obtained by, say, using the capital to buy a bond which offers a 10% interest rate. Since a firm's or region's best alternative use of capital will often return profits higher than those obtainable from bond interest rates, we will call the interest rate at which we present value an alternative the firm's (region's) cost of capital. This is consistent with our basic definition of cost: for example, the region's cost of capital is the growth of regional income foregone by tying up capital which could return this growth if employed elsewhere.

Our use of present value raises the problem of what cost of capital we should use in our analyses, especially when the decisionmaker in question is the region. Clearly some of the inhabitants of New England have different investment opportunities than others. From the point of view of the region as a whole, what we require is the weighted average of these individual costs of capital. Since it would be difficult to say just what this average is, we will run most of our analysis over a range of cost of capital running from 8 to 15% per year.

At this point, we had better say a word about inflation. All our analyses are based on 1972 prices. Thus, for example, if a particular oil rig operator's services were priced at \$5.50 an hour in 1972, we will assume that his wage is \$5.50 an hour in 1982. In reality, the general price level in the country may have risen so that in 1982 prices the operator is earning, say, \$6.00 an hour in 1982. However, we will implicitly deflate these prices back to 1972 dollars to put everything on the same basis. This holds for all future prices and costs. In particular, this procedure requires that we use inflation-free cost of capital in obtaining present values. For instance, if an investor's best employment of capital is to buy a bond at a market interest rate of 10% for a given period during which price levels were rising at 3% per year, the investor will realize a 7% growth in his income in real purchasing power (in constant value dollars). Thus, in this report when we speak of a cost of capital of 8%, we are talking about 8% net of inflation, which at present would correspond to a market interest rate of 10 or 11%.

I.1.5 <u>Application of the regional income approach to potential New England petroleum developments</u>

It is now time, perhaps past time, to begin to apply some of the foregoing thoughts to the specifics of potential New England petroleum developments. As outlined in Section I.1.1, our approach will be to (a) hypothesize a number of potential combinations of oil and gas find, refinery location, crude and product transport system and (b) generate for each such combination an estimate of its effect on regional income. In so doing, our basic procedure will be:

a) Assume an oil consumption growth rate and regional cost of capital.* Escalate the 1971 deliveries of each of four oil product classes (gasoline, jet fuel/kerosene, distillate heating oils, residual fuel oils) to each of eight major New England products reception ports (Searsport/Bucksport, Portland, Portsmouth, Boston, New Bedford, Providence, New Haven, and Bridgeport) at the assumed consumption growth rate for the next 50 years.

b) Require each hypothetical development to deliver the resulting amount of each product to each port through the life of the analysis, generally taken to be 1978 through 2018 in the sequel.

c) Estimate the market price of the products delivered to the reception ports through time for the hypothesis under analysis. From these prices, we will obtain the direct cost to the regional consumer of his oil consumption.

d) From the direct payments by consumers we will deduct estimates of:

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*Several combinations of consumption growth rate and regional cost of capital will be studied.

1) the profits to regional investors associated with the development,
2) the region's share of any federal revenues,
3) the increase in net revenues to regional public bodies,
4) the increase in income of regional labor employed by the development,

to obtain an estimate of the cost to the region of this consumption.*

e) For those alternatives which involve a regional gas find the above regional cost is adjusted downward by the present value of the difference between our estimate of what the region would be willing to pay for the gas delivered to a regional trunk line and the regional cost of delivering the gas to the line.**

The result for each hypothetical development is an estimate of the present value of the market value of the consumption forgone by the region in order to obtain its assumed oil energy consumption through the life of the analysis. Suppose for one hypothesis this number turns out to be $10 billion and for another, $11 billion. Then this implies that we estimate that moving from the second alternative to the first would be equivalent to handing to the region in 1972, on a one-shot basis, a billion dollars' worth of real income. Of course, the region would actually see this increase spread throughout the life of the analysis, some 40 years. However, this is the equivalent amount received now at the assumed regional cost of capital

*These four portions of the consumers' outlays are not costs to the region.

**As we shall see, the regional energy market is so large that even a very large gas find will result in no exportation outside the region. The basic assumption here is that this gas will displace some of the oil for which the regional cost was already computed.

of all these future increases resulting from moving from the second alternative to the first.

Once we have an estimate of the present value of the regional cost of each of our hypotheses, we will compare these numbers in order to know how much the region gains or loses in equivalent purchasing power received now from pursuing one hypothesis rather than another.

In obtaining our estimate of the regional cost of each hypothesis, we will move in a stepwise fashion as follows. Chapter I.2 obtains an estimate of the national cost of each hypothesis under the assumption of full employment by simulation of the resulting production, transport, and processing activities. This analysis also generates estimates of tanker and barge traffic, oil and gas flows, number of platforms and wells through time which are used in the environmental analyses. At the same time, Chapter I.2 generates the investor's cost of each of these developments in order to discover under what circumstances an investor would choose to develop a find and how he would like to develop it.

Suppose Chapter I.2 determines that the difference between one alternative and another in terms of present value of national cost is two billion dollars. This increase in national income can show up in several places:

1) a decrease in consumer prices of petroleum products;

2) an increase in after-tax profits of petroleum industry shareholders;

3) an increase in the net revenues of federal and regional public bodies.

For our purposes, we are only directly interested in that portion of this increase in national income that accrues to New England, Uncle Eph's share. Chapter I.3 analyzes the likely response of market prices to a change in investor's cost f.o.b. the products reception ports.

The extent of this change is important, for almost all of it will accrue to New Englanders.

We shall see that the effect on market price (on regional consumer's cost) of a given change in investor's cost can range from nil to the full amount of the change, depending on where it occurs in the system and the policy variables assumed.

Chapter I.4 considers item (2) from the point of view of the region, which depends on the share of New England ownership of the production and distribution facilities. More importantly, Chapter I.4 also examines how much of item (3) will accrue to New Englanders, which will be critically dependent on the degree of control the region has over the resources in situ.

Chapter I.5 relaxes the assumption of full employment in order to estimate the changes in regional income due to changes in amount of employment and to respending.

Chapter I.6, which depends heavily on the second volume, analyzes the change in regional income associated with the effect of offshore oil production on the Georges Bank fishery. Chapter I.7 investigates the impact on regional income of nearshore spills.

Finally, Chapter I.8 combines all the earlier arguments to arrive at a series of estimates of the present valued regional cost of each of the hypothetical developments. It then compares these numbers to estimate the change in real regional income associated with opting for one such alternative rather than another.

Chapter I.2
Simulation of Petroleum Development Hypotheses

I.2.1 The basic structure of the model

This chapter describes the petroleum development simulation program through which we have estimated the effect of various petroleum development hypotheses on regional income. This program takes as input 12 key variables describing the development hypothesis currently under analysis:

1) Regional oil consumption growth rate
2) Regional cost of capital
3) The foreign price of crude and residual fuel thru time
4) Federal import policy
5) Federal natural gas pricing policy
6) Federal or regional ownership of Georges Bank petroleum
7) Amount of Georges Bank oil in place
8) Amount of Georges Bank gas in place
9) Number of fields discovered
10) Refinery output
11) Refinery location
12) Products distribution system option

In addition, the program takes as input a large number of variables of secondary importance, describing the Georges Bank discovery, the refinery, and the various crude and products transport systems in some detail. These secondary variables are described in the following sections.

With respect to regional consumption growth, the program as presently constituted considers two consumption

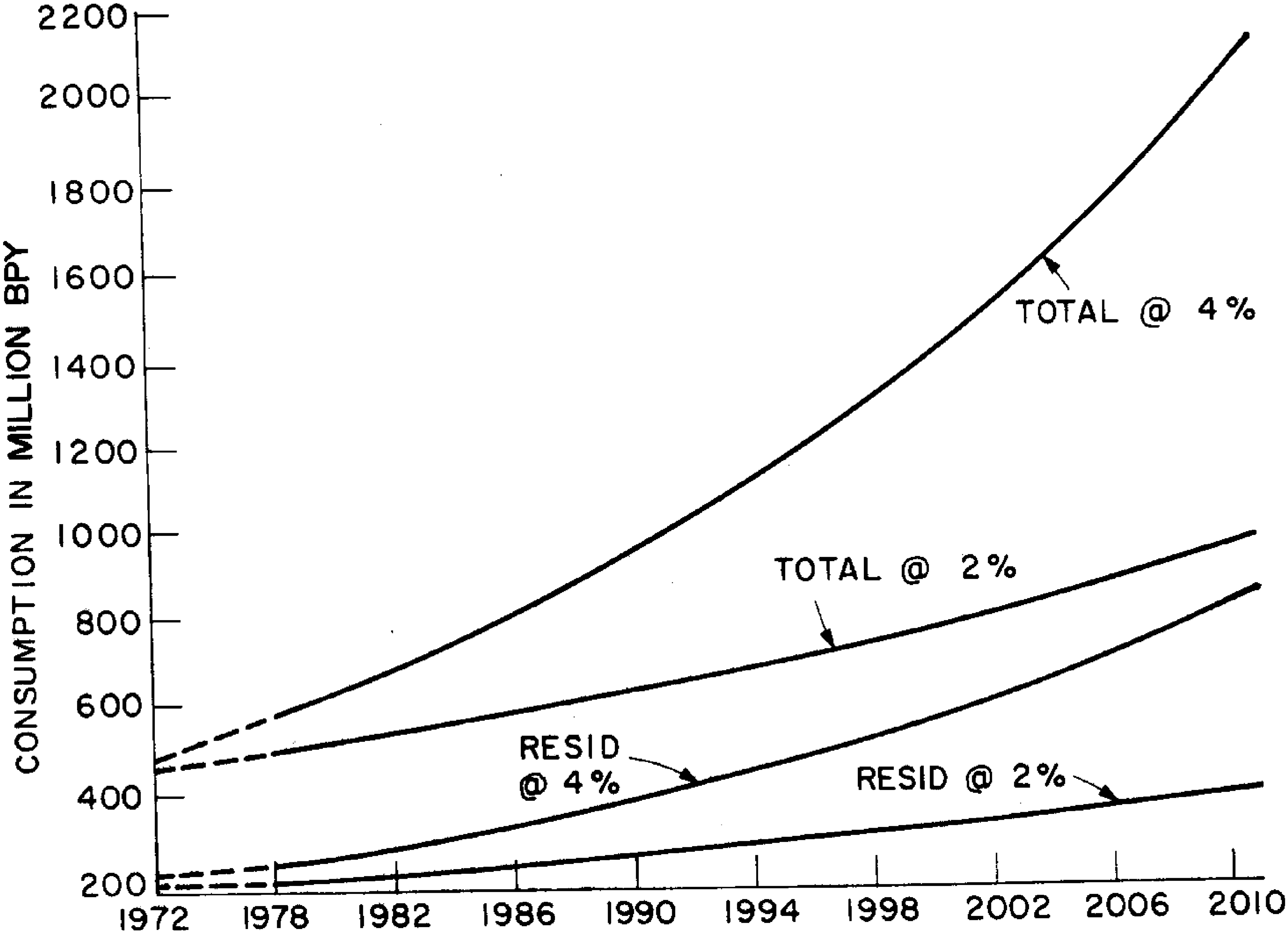

FIGURE I.2.1. 2% AND 4% CONSUMPTION GROWTH HYPOTHESES growth rates, 2% and 4% per annum.* These numbers have been chosen to represent low and high estimates of future consumption respectively. During the period 1950 to 1971, the New England consumption of distillate oils has grown at 4.7% while that of residual fuel at 4.1%. Future growth will almost certainly be lower than this. During the period 1950-1971 many electrical utilities were switching from coal to oil, population growth rate is slowing, and nuclear power is likely to provide an increasing proportion of the region's energy consumption. How much lower we don't know. We have chosen 2% per annum to represent a reasonable lower bound. These two projections with respect to consumption through the next 50 years are displayed in Figure I.2.1.

As presently set up, the program investigates two regional costs of capital: 8% and 15% per year - once again chosen to represent low and high estimates. In the runs displayed in this report, it is assumed that the investor's cost of capital and the national cost of capital are equal to the regional cost of capital. The program has the ability to accept differing costs of capital for these decisionmakers and in fact the ability to vary the investor's debt equity ratio. No use of this ability is made in this report. The program is therefore operating under the assumption that all the investor's capital costs the same and is treated the same for tax purposes.

In this report, all our analyses cover the development hypotheses over the period 1978 to 2018, 1978 being chosen as about the earliest that large-scale changes in the system could be in operation. The choice of 2018 as cut-off date is arbitrary. The actual cut-off date used makes little difference as the present value process gives little weight

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*Other growth rates can be investigated by minor modification to the program. The same thing is true for all the numerical variables.

to the distant future. Foreign crude payments turns out to be an extremely important variable from the point of view of regional income. The program considers two assumptions:

1) Payments to exporting nations remain at 1972 levels in terms of 1972 dollars;

2) Payments to exporting nations rise to $4.00 (1972 dollar) a barrel in 1980 and remain at that level thereafter.

These assumptions are discussed in Section I.2.2.

The program considers two alternatives with respect to import quota policy. One, no import quota; two, a quota policy which maintains domestic crude prices about $1.00 in excess of what they would be without the quota. Chapter I.3 discusses these hypotheses.

Two alternatives with respect to gas regulatory policy can be handled. One, present regulatory policy, gas sold at FPC's estimate of average investor's cost; two, complete deregulation, gas price determined by supply and demand. Chapter I.3 also covers these alternatives.

The program investigates two situations with respect to Georges Bank petroleum:

1) Federal control of the Bank. All lease payments and royalties accrue to the federal government;

2) Regional control of the Bank. All lease payments and royalties accrue to regional governments.

As can be seen, our philosophy throughout has been to bracket the problem in order to display the swing when one moves from one extreme to another.

The remaining major variables are physical in nature. The program can handle a range of finds running from no oil or gas to an extremely large oil and/or gas discovery in any number of separate structures. The program analyses a range of both pipeline and tanker systems for bringing the find to shore. The program as a whole, but not the reservoir model, is limited to finds such that, even at maximum production, all the oil and gas produced could be consumed in New England. We shall see that it will take a very large find before this is not the case.

Two options with respect to refinery output have been investigated:

1) Refinery produces a mix of gasoline, kerosene/ jet fuel, distillate, fuel oil consistent with 1970 New England consumption of all oil except residual fuel.

2) Refinery produces a mix of gasoline, jet fuel, distillate and residual consistent with all 1970 New England oil consumption.

For those runs in which the refinery does not produce residual fuel, .5% sulphur resid is imported from Venezuela.

The program as presently set up can accept any one of five refinery locations:

1) Present Delaware Bay

2) Delaware Bay with 65' depth capability

3) Nova Scotia (Pt. Tupper)

4) Deepwater Maine (Machiasport)

5) Southeastern New England (Dighton)

These locations have been chosen to represent a representative spectrum of the alternatives. Other locations can be investigated with minor modifications to the program.

The program operates under the assumption that all New England oil consumption (less possibly residual, depending on the refinery output option) is refined at a single location. This is unrealistic. For one thing, it would require the establishment of a better than one million barrel per day refinery in 1978 for the last three options. The industry would be unwilling to bring on this much capacity in one year due to the overcapacity that would be generated, although the growth in East Coast consumption would swallow this increase if it were brought on over a period of five (ten) years at the 4% (2%) growth rate. During the interim, regional consumption would be processed in a number of locations. For another thing, it is possible that the various companies supplying this new capacity would do so from different locations. Nonetheless, the assumption of a single refinery is consistent with our basic philosophy of operating with the extremes in order to demonstrate the swings. Thus, for example, our Machiasport option might be thought of as representative of an extreme case of the basic policy of accepting a large refinery in northern New England. In actual fact, we can be quite sure that, even if this policy is followed, some of the region's consumption will be refined elsewhere, at least for a while. From an overall policy point of view, this single refinery assumption is quite useful. At a more detailed level, such as the evaluation of a deepwater products reception terminal off of Boston, it causes us some problems, as we shall see.

The program considers three different products distribution systems:

1) The present tanker/barge system based on present terminals;

2) The present system with the exception of a single-point mooring (SBM) in 65' of water off Boston;

3) A pipeline products distribution extending from Bridgeport to Portland. As presently constituted, the program evaluates this option only for the southeastern New England refinery location.

Undoubtedly, the most important variable which the program does <u>not</u> comprehend is sulphur content. Foreign crude costs are based on average quality (no sulphur restriction) oil. The refinery model employs extensive hydrodesulphurization and is costed accordingly. The same is true for Georges Bank oil. Thus, we are undervaluing a low sulpher content find and overvaluing a very high sulphur content find.

The output of the program is available in two forms:

1) A rather complete tabulation running some 15 pages per case describing the resulting system and flows in considerable detail; offshore construction and oil and gas production by field and year, detailed breakdown of refinery costs and product mix, pipeline diameters and power by year of installation, etc.

2) An abbreviated summary tabulation such as that shown in Figure I.2.2. We will find it useful to refer to Figure I.2.2 in describing the mechanics of the program's operation.

The program consists of four major subroutine packages. The first, known as EXCRUDE, designs and costs the system which delivers extraregional crude to the refinery. The second package, REFINE2, designs and costs the refinery itself,and the third package, PRODIST, designs and costs the system which delivers the products from the refinery to the eight New England products reception ports. The fourth package, called OFFSHOR, contains the reservoir model and handles the Georges Bank discovery proper. In addition, there are a number of subroutines which perform such functions as:

1) estimating regional petroleum products prices under the development hypotheses, according to the analysis of Chapter I.3, and thereby developing the direct cost to the regional consumer of his oil consumption and the gross revenues of the suppliers;

```
******************** DISTRIBUTION AND REFINING SUMMARY *******************

REFINERY LOCALE: DIGHTON        STARTUP YEAR: 1978  GROWTH RATE: 2.0 %/YR
REFINERY OUTPUT: NO RESID       LAST YEAR:    2011  DISTRIBUTION: PIPE

                                                        1978    2011
EXTRAREGIONAL *  TANKER DWT:     230060
CRUDE         *  ANNUAL CAP: 7.670E+06   # NEEDED=>  35      80
***************  TRIPS/YR:            6
                                                TRANS    TOTAL    REG. LABOR
                   THROUGHPUT LANDED COST       /BBL     /BBL       COST
     PV @ 15.0 %    5.220E+08  $ 2.355E+09 $ 0.904 $ 2.554 $ 2.260E+06
     PV @  8.0 %    2.643E+09  $ 6.160E+09 $ 0.681 $ 2.331 $ 4.453E+06

REFINING *                 TOTAL      TOTAL      CONSTR          TOTAL
COSTS    *     PV          COST       /BBL       LABOR           LABOR
**********  @ 15.0 %   $ 1.681E+09 $ 1.689 $ 1.479E+08 $ 4.446E+08
            @  8.0 %   $ 4.145E+09 $ 1.513 $ 2.543E+08 $ 1.145E+09

PRODUCT   * PV COST:    $ 5.416E+07 @ 15.0 %==>$ 1.214E+08 @ 8.0 %
DIST      * PV /BBL:    $ 0.054     @ 15.0 %==>$ 0.044      @ 8.0 %
*********** PV LABOR:   $ 1.313E+07 @ 15.0 %==>$ 2.934E+07 @ 8.0 %

           1978          1979          1989          1999          2009
 COST  $ 7.341E+07  $ 3.682E+06  $ 7.356E+06  $ 1.103E+07  $ 1.239E+07
 ROW   $ 1.320E+07  $ 6.600E+06  $ 6.600E+06  $ 6.600E+06  $ 6.600E+06
 SEARSPORT=> DWT= 20000 TRIPS/YR=316   # IN 1978= 1   # IN 2011= 1

                                                   1978    2011
RESID *   TANKER DWT:      50000
*******   ANNUAL CAP: 5.497E+06      @ NEEDED=>    21      41
          TRIPS/YR:          29
                                                TRANS    TOTAL    REG. LABOR
                    THROUGHPUT LANDED COST      /BBL     /BBL       COST
     PV @ 15.0 %    5.683E+08 $ 1.909E+09 $ 0.259 $ 3.359 $ 0.000E+00
     PV @  8.0 %    1.617E+09 $ 5.345E+09 $ 0.206 $ 3.306 $ 0.000E+00


                MARGINAL  COST  DATA  @ 15.0 %
                |        CRUDE      |   RESID DEREG    |    RESID REG      |
 NO IMP NO ESC  |      2.644E+09    |     1.909E+09    |     1.909E+09     |
 IMP    NO ESC  |      4.227E+09    |     1.909E+09    |     1.909E+09     |
 NO IMP ESC     |      5.175E+09    |     3.292E+09    |     3.292E+09     |
 IMP    ESC     |      6.211E+09    |     3.292E+09    |     3.292E+09     |


                MARGINAL  COST  DATA  @  8.0 %
                |        CRUDE      |   RESID DEREG    |    RESID REG      |
 NO IMP NO ESC  |      6.643E+09    |     5.345E+09    |     5.345E+09     |
 IMP    NO ESC  |      1.151E+10    |     5.345E+09    |     5.345E+09     |
 NO IMP ESC     |      1.374E+10    |     9.365E+09    |     9.365E+09     |
 IMP    ESC     |      1.659E+10    |     9.365E+09    |     9.365E+09     |
```

The notation 1.0E+03 is computerese for 1,000. The "E" means the exponent of 10. Figure I.2.2:

Figure I.2.2 Sample Run. Short Form.

***************************OFFSHORE PACKAGE ***************************

OIL IN PLACE: 3000 MMBBL	OIL VISCOSITY: 4.0 CP
GAS IN PLACE: 3000 MMMCF	GAS SP. GR.: 0.6
VERT. DEPTH: 10000 FT	OIL API: 30.0
PRESSURE: 5000 PSI	FORM. THICK: 75.0 FT
PERMEABILITY: 0.1 DARCYS	WATER DEPTH: 210.0 FT
POROSITY: 20.0 %	SLANTANGLE: 45.0 DEG
REINJECTION: 0.0 %	TEMPERATURE: 200.0 DEG F
DRIVE: GAS SOLUTION	NO. FIELDS: 5
OIL LIMIT: 1000 BPD	GAS LIMIT: 15 MMCFD.
% LEASE: 75.0	

	PV @ 15.0 %		PV @ 8.0 %	
EXPLORATION OUTLAYS (1976)	1.204E+07		1.648E+07	
EXPLORATION PER BBL EQUIV.	0.061		0.043	
TOTAL ROYALTY PAYMENTS (@ $0.45 /BBL & 12.5 % OF $/MCF):	4.466E+08		9.368E+08	
PRODUCTION COSTS:	1.611E+08		2.642E+08	
PRODUCTION PER BBL EQUIV.	0.823		0.694	
	PIPELINE	TANKER	PIPELINE	TANKER
TRANSPORTATION COSTS (OIL)	1.781E+07	2.03E+07	2.596E+07	3.17E+07
TRANSPORTATION COSTS (GAS)	4.821E+07	0.00E+00	7.028E+07	0.00E+00
REGIONAL LABOR COSTS	4.453E+06	6.32E+06	6.490E+06	1.38E+07
TOTAL NATIONAL COSTS	1.910E+08	1.93E+08	3.066E+08	3.12E+08
NATIONAL COSTS /BBL EQUIV.	0.975	0.988	0.805	0.820

TOTAL PLATS	TOTAL WELLS	TOTAL TANKER	TANKER TRIPS	DWT	OIL PIPE DIAM(IN)	GAS PIPE DIAM(IN)	OIL (MBBL)	GAS (MMCF)
5	120	1	154	80000	20	36	52560	41910
10	240	1	154	80000	20	36	70080	56725
10	240	1	154	80000	20	36	70080	76724
10	240	1	154	80000	20	36	70080	142814
10	240	1	154	80000	20	36	70080	328317
10	240	1	154	80000	20	36	60803	709070
10	240	1	154	80000	20	36	25743	532444
10	240	1	154	80000	20	36	11059	262380
10	240	1	154	80000	20	36	5539	126669
10	240	1	154	80000	20	36	3034	64320
10	240	1	154	80000	20	36	1772	34573
10	240	1	154	80000	20	36	1017	18116

THE PRESENT VALUE THROUGHPUT EQUIVALENT IS: 1.958E+08 @ 15.0 % AND 3.809E+08 @ 8.0 %

PERCENT RECOVERY: OIL= 14.7 % GAS= 79.8 %

Figure I.2.2 continued

********* SUMMARY SHEET 1 NO ESCALATION OF FOREIGN CRUDE PRICE *********

	PV @ 15.0 %		PV @ 8.0 %	
COST OF GB PETROLEUM:	1.910E+08		3.066E+08	
COST OF EXREG CRUDE:	2.355E+09		6.160E+09	
COST OF DISTRIBUTION:	5.416E+07		1.214E+08	
COST OF GAS PIPELINE:	4.821E+07		7.028E+07	
COST OF EXREG RESID:	1.909E+09		5.345E+09	
COST OF REFINING:	1.681E+09		4.145E+09	
GROSS REG PAYROLL:	4.645E+08		1.186E+09	
TOTAL COST OF OPTION:	6.238E+09		1.615E+10	
** IMPORT QUOTA ******				
	PRESENT	DEREGULATE	PRESENT	DEREGULATE
CONSUMER COST:	8.203E+09	8.345E+09	2.194E+10	2.224E+10
PROFITS:	1.500E+09	1.521E+09	4.667E+09	4.710E+09
LEASE PAYMENTS:	8.713E+07	1.811E+08	1.942E+08	3.866E+08
REGIONAL CONTROL GB:				
REGIONAL REVENUES:	3.733E+08	4.940E+08	8.610E+08	1.109E+09
FEDERAL REVENUES:	1.364E+08	1.364E+08	3.492E+08	3.492E+08
REGIONAL COST-(1):	7.813E+09	7.791E+09	2.084E+10	2.069E+10
REGIONAL COST-(2):	7.720E+09	7.699E+09	2.087E+10	2.092E+10
REGIONAL COST-(3):	7.528E+09	7.506E+09	2.038E+10	2.043E+10
FEDERAL CONTROL GB:				
REGIONAL REVENUES:	2.215E+08	2.315E+08	5.426E+08	5.631E+08
FEDERAL REVENUES:	2.882E+08	3.988E+08	6.676E+08	8.953E+08
REGIONAL COST-(1):	8.002E+09	8.133E+09	2.141E+10	2.167E+10
REGIONAL COST-(2):	7.910E+09	8.040E+09	2.117E+10	2.144E+10
REGIONAL COST-(3):	7.717E+09	7.847E+09	2.069E+10	2.095E+10
NO QUOTA				
CONSUMER COST:	6.620E+09	6.762E+09	1.708E+10	1.737E+10
PROFITS:	4.354E+07	6.484E+07	1.893E+08	2.330E+08
LEASE PAYMENTS:	8.713E+07	1.811E+08	1.942E+08	3.866E+08
REGIONAL CONTROL GB:				
REGIONAL REVENUES:	2.468E+08	3.675E+08	4.739E+08	7.221E+08
FEDERAL REVENUES:	1.364E+08	1.364E+08	3.492E+08	3.492E+08
REGIONAL COST-(1):	6.366E+09	6.345E+09	1.640E+10	1.624E+10
REGIONAL COST-(2):	6.273E+09	6.252E+09	1.642E+10	1.647E+10
REGIONAL COST-(3):	6.081E+09	6.059E+09	1.593E+10	1.599E+10
FEDERAL CONTROL GB:				
REGIONAL REVENUES:	9.496E+07	1.050E+08	1.555E+08	1.761E+08
FEDERAL REVENUES:	2.882E+08	3.988E+08	6.676E+08	8.953E+08
REGIONAL COST-(1):	6.556E+09	6.686E+09	1.696E+10	1.723E+10
REGIONAL COST-(2):	6.463E+09	6.593E+09	1.672E+10	1.699E+10
REGIONAL COST-(3):	6.270E+09	6.400E+09	1.624E+10	1.651E+10

Figure I.2.2 continued

********** SUMMARY SHEET 2 ESCALATED FOREIGN CRUDE PRICE **************

	PV @ 15.0 %		PV @ 8.0 @	
COST OF GP PETROLEUM:	1.910E+08		3.066E+08	
COST OF EXREG CRUDE:	4.616E+09		1.276E+10	
COST OF DISTRIBUTION:	5.416E+07		1.214E+08	
COST OF GAS PIPELINE:	4.821E+07		7.028E+07	
COST OF EXREG RESID:	3.292E+09		9.365E+09	
COST OF REFINING:	1.681E+09		4.145E+09	
GROSS REG PAYROLL:	4.645E+08		1.186E+09	
TOTAL COST OF OPTION:	9.883E+09		2.677E+10	
IMPORT QUOTA				
	PRESENT	DEREGULATE	PRESENT	DEREGULATE
CONSUMER COST:	1.157E+10	1.192E+10	3.104E+10	3.177E+10
PROFITS:	1.036E+09	1.089E+09	2.883E+09	2.993E+09
LEASE PAYMENTS:	2.949E+08	5.277E+08	5.803E+08	1.067E+09
REGIONAL CONTROL GB:				
REGIONAL REVENUES:	5.538E+08	8.553E+08	1.126E+09	1.746E+09
FEDERAL REVENUES:	1.364E+08	1.364E+08	3.492E+08	3.492E+08
REGIONAL COST-(1):	1.090E+10	1.085E+10	2.932E+10	2.892E+10
REGIONAL COST-(2):	1.081E+10	1.076E+10	2.973E+10	2.986E+10
REGIONAL COST-(3):	1.062E+10	1.056E+10	2.924E+10	2.937E+10
FEDERAL CONTROL GB:				
REGIONAL REVENUES:	1.992E+08	2.240E+08	4.212E+08	4.731E+08
FEDERAL REVENUES:	4.960E+08	7.677E+08	1.054E+09	1.622E+09
REGIONAL COST-(1):	1.139E+10	1.171E+10	3.064E+10	3.131E+10
REGIONAL COST-(2):	1.130E+10	1.162E+10	3.040E+10	3.107E+10
REGIONAL COST-(3):	1.111E+10	1.143E+10	2.992E+10	3.059E+10
NC QUOTA				
CONSUMER COST:	1.053E+10	1.088E+10	2.819E+10	2.892E+10
PROFITS:	8.336E+07	1.361E+08	2.587E+08	3.690E+08
LEASE PAYMENTS:	2.949E+08	5.277E+08	5.803E+08	1.067E+09
REGIONAL CONTROL GB:				
REGIONAL REVENUES:	4.761E+08	7.727E+08	9.004E+08	1.521E+09
FEDERAL REVENUES:	1.364E+08	1.364E+08	3.492E+08	3.492E+08
REGIONAL COST-(1):	9.956E+09	9.902E+09	2.671E+10	2.632E+10
REGIONAL COST-(2):	9.863E+09	9.809E+09	2.712E+10	2.725E+10
REGIONAL COST-(3):	9.670E+09	9.617E+09	2.664E+10	2.677E+10
FEDERAL CONTROL GB:				
REGIONAL REVENUES:	1.165E+08	1.413E+08	1.958E+08	2.477E+08
FEDERAL REVENUES:	4.960E+08	7.677E+08	1.054E+09	1.622E+09
REGIONAL COST-(1):	1.045E+10	1.077E+10	2.803E+10	2.870E+10
REGIONAL COST-(2):	1.035E+10	1.067E+10	2.779E+10	2.846E+10
REGIONAL COST-(3):	1.016E+10	1.048E+10	2.731E+10	2.798E+10

Figure I.2.2 continued.

2) computing the suppliers' federal and regional tax payments and after-tax profits;

3) combining regional consumer costs, regional payrolls, investor profits and public revenues into an estimate of the overall present valued regional cost of the development over the life of the analysis.*

In the remainder of this chapter we will consider each of the four subsystem packages in detail. In Chapter I.3 we will present the analysis through which the cost to the consumer is determined and in Chapter I.4, our treatment of public and private profits. Chapter I.5 offers the rationale behind our analysis of regional payrolls. Finally, in Chapter I.8 the overall results are presented.

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*The program is written in PL/1 under the Optimizing Compiler. In total it contains some 4,000 executable statements. It presently exists in object form as a load module located on disk at the M.I.T. Information Processing Center. The load module occupies approximately 175,000 bytes of storage and requires approximately 230,000 bytes of main storage to execute. In addition to the program proper, there are several files containing semi-permanent data on disk which is referenced by the program during execution. A run such as that shown in Figure I.2.2 requires about 3 seconds of CPU time on an IBM 370/155.

I.2.2 The extraregional crude package

The function of the extraregional crude package, EXCRUDE, is to estimate both the national cost and investor cost of foreign crude landed at a specified refinery for the hypothesis currently under analysis. EXCRUDE takes as input the annual amount of crude to be delivered at the refinery through the life of the project, the distance from the crude oil source to the refinery, draft limitations at loading and discharge ports, the time the vessel is at reduced speed in the vicinity of the loading and discharge points, the cost of the crude to the investor at the loading flange before payments to the exporting nation and the amount of these payments to the exporter through time. In general, the values of these variables will change from run to run of the program.

In addition, EXCRUDE has as input a semi-permanent data file which contains data on vessel carrying capacity versus draft, and vessel speed, loading and discharge rate, at-sea and in-port fuel consumption, all as a function of vessel deadweight (carrying capacity). This file also contains shipowner cost data (initial cost, crew, insurance, maintenance, administration expense and port charges) as a function of deadweight as well as fuel price, operating days per year, port charges and terminal cost data - the latter as a function of terminal location and draft. This semi-permanent data may be changed by means of IBM utility programs, but throughout the analyses used in this report these variables have been held fixed at the values outlined below.

The basic logic of EXCRUDE is as follows. The program examines the draft limitations at each end of the route and compares them with the vessel capacity versus draft table to determine the largest conventional tanker which can serve this route. It then considers the amount of oil to be moved in the first year of the project, determines the number of tankers of this size required to move this amount (given time off for maintenance and down time at SBM's, etc.) and charters that number at a charter rate which over the life of the ship will return the shipowner his cost of capital. It then moves on to the second year and repeats this process and so on through the life of the project. Finally, it determines the present value of the national cost and investor cost of this crude transport system.

Our costing of extraregional crude is broken down into two categories: (a) those losses in U.S. national income associated with obtaining the oil at the foreign loading port; (b) those losses associated with transport to the refinery. We will begin with the former.

I.2.2.1 The national cost of foreign crude f.o.b.

In the runs analyzed below, we have assumed that the Persian Gulf is the extraregional crude source. While presently only 6% of U.S. imports emanate from the Persian Gulf, it is expected to increase rapidly. Hence, this is the source on the margin and as such determines the cost to the United States of imported crude f.o.b. Further, given the tremendous capability of the Persian Gulf fields to expand production, this situation will probably persist throughout the remainder of the century. Oil that is nearer to the U.S. will command a premium which is determined by the difference in transport expenses between the point of origin of this oil and Persian Gulf oil.* Therefore, the cost of Persian Gulf crude will determine the cost of imported oil to this country.

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*In fact, a clause which varies the price of Mediterranean and Caribbean oil as the tanker charter rate fluctuates is an explicit part of the OPEC (Organization of Petroleum Exporting Countries) agreements. However, the differential was obviously and substantially overestimated in the 1970 bargaining, resulting in overpricing and idle capacity in these two areas.

The cost to the United States of Persian Gulf crude at the loading flange in the Gulf is the sum of (a) the oil companies' actual expenses on a present value basis in producing the oil and moving it to the coast and (b) the payments made to the exporting countries. With respect to the former, Adelman (1972) has estimated that the unit resource costs of producing oil in the Big Four Persian Gulf countries (Iran, Iraq, Kuwait, Saudi Arabia) are approximately 10¢ per barrel, of which 5¢ is investment and 5¢ is operating expenses. Even under the pessimistic assumption of zero new-field discoveries and a rapid production growth of 11% per year (but expansion of reserves in old fields by a factor of .5), which would result in reserve/production ratio decline by 1985 to about 15, from a current 60+, Adelman argues that operating and development costs would no more than double. This increase in operating-development cost serves as a proxy for exploration cost, because at the margin the two are substitutable. The operator, or the industry as a whole, can choose either to look for new pools in old fields and develop more intensively, or to search for new fields.

Since these assumptions of zero discoveries and 11% annual growth are quite pessimistic, the resource cost of Persian Gulf crude can be projected with a high degree of confidence at not more than 20¢ per barrel in terms of 1972 dollars. In fact, the real resource cost has declined by about 50% since 1960 in money terms, despite the intervening price inflation, during which time output per man-year has multiplied by a factor of 2 to 3. It is dangerous to project a further decline, but if there is any inertia in the system, an increase is unlikely.

To this resource cost we must add the payments made to the exporting nation to determine the f.o.b. cost of foreign crude to the U.S. These payments are currently many times the resource cost and the amount of these payments is by far the most important single variable with respect to foreign crude. It is also the most uncertain.

Currently, these payments are running at about $1.45 per barrel for 34° Persian Gulf oil. Historically the real payments (tax and royalty) remained almost constant from about 1957 through 1969. Since this time, the real payments have been successively and steeply increased. It is generally expected that payments will increase in the 1970's; but there is some controversy over how long the trend will continue. These drastic increases came at a time when growth in world consumption was slowing down sharply and substantial excess capacity was appearing in several large producing areas, notably Venezuela and Iraq, where the cutbacks by the operating companies were due to their having more than enough capacity elsewhere which could be operated at a lower tax plus cost.

Clearly, we are dealing with a monopolistic market. Basically, it is a bilateral monopoly. The OPEC nations have most of the available oil. The developed nations have the only market. But the sellers have recently organized into an effective cartel; the consumer nations' governments have not only not so organized, but individually have gone out of their ways to cooperate with the exporters. Their reasons do not matter here. Whether they will continue to operate in this self-defeating manner is impossible to way. See Adelman (1972) for a complete discussion.

If they do, or if they remain passive, it is quite likely the real payments to the exporting nations will rise sharply, for the current f.o.b. price of crude in the Persian Gulf, about $1.85 per barrel, is only a small percentage of the final price of the products produced from this oil. The average product price in Europe in 1969 was about $13 per barrel, when the average Persian Gulf crude price was about $1.30. Hence if the price rose by 300%, to $5.20, the average price of all products as a whole would increase by only 30%.

As we shall see, the demand for many oil products, most notably gasoline, is quite insensitive to price. Hence a 30% rise in price would probably not affect volume. Thus, an unmolested sellers' monopoly could profitably raise the export payments to levels of $4.00 and $5.00 per barrel. And in fact, a Department of State spokesman recently predicted such levels by 1980.

On the other hand, the basic bargaining position of the market nations is not that bad if they organize to take advantage of it. If the developed countries abandon the nonsensical procedure of having the oil companies negotiate for them, which companies have little real clout and only a moderate or zero stake in the outcome of the negotiations,* store enough oil to make the threat of a buyers' strike credible, then it is quite possible that the market countries could drive a rather hard bargain. One large defection from the exporters' ranks would break their cartel and destroy the exporters' bargaining position. The per capita incomes and political instabilities of at least some of the large exporters make a prolonged loss in oil revenues a rather unattractive prospect.

In the face of this uncertainty with respect to the future payments to the exporting nations, we have chosen to run all our analyses for two quite different assumptions:

1) Payments to exporting nations escalating rapidly to $4.00 a barrel in 1972 dollars in 1980 and contant thereafter:
2) Real payments to exporting nations remaining at slightly over present levels, $1.45 a barrel for standard Persian Gulf crude.

We regard these as reasonably extreme cases.

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* The loss in oil company profits due to a rise in payments to exporters is only a small proportion of the loss in market nation real income. In fact, investment analysts welcomed the Tehran agreement on the theory that the resulting price rise would improve industry profits. A rise in OPEC payments is certainly favorable to those companies who have a large investment in producing properties which do not come under the OPEC agreements.

I.2.2.2 The cost of crude transport

With respect to extraregional crude transport, the extraregional crude package in essence employs the largest conventional tanker which meets the specified draft limitations of the route. The range of tanker drafts which it can accommodate is 30 feet through 80 feet, corresponding to deadweights of 30,000 tons through 300,000 tons. The relationship between draft and deadweight which the program uses is given in Figure I.2.3, which also shows a scatter diagram of the drafts of recent tanker designs. The curve is a second order regression fit to a random sample of 400 tankers analysed by Hunter and Watson (Hunter, 1969). The tankers which the program uses are conventional 15.5 knot, circa 1970 designs with the exception that slow speed diesel power is assumed throughout. At present, tankers in excess of 200,000 tons employ steam power due mainly to the present upper bound on the size of diesels being manufactured. However, the established trend is toward larger diesels which will be competitive with steam. The fuel consumption and loading/unloading rates assumed for these ships are given in Figures I.2.4 and I.2.5, which also indicates the sources for the data points. Unloading times run from about 10 hours for the smallest tankers to 20 hours for the largest. Round trip fuel is loaded in the loading port. The EXCRUDE package assumes foreign building and foreign flag operation.

The shipowner costs assumed for these ships are given in Figure I.2.6 and Table I.2.1. Figure I.2.6 is based on and displays the results of a survey of the reported prices of recent deliveries and orders. The dots (squares) represent foreign (domestic) contracts. The stars and triangles represent average ship prices computed by a number of industry sources. All the expenses of Table I.2.1 assume foreign flag building and operation. Values for intermediate deadweights are obtained by linear interpolation. The crew costs, which include benefits, repatriation and subsistence, are based on a relatively expensive

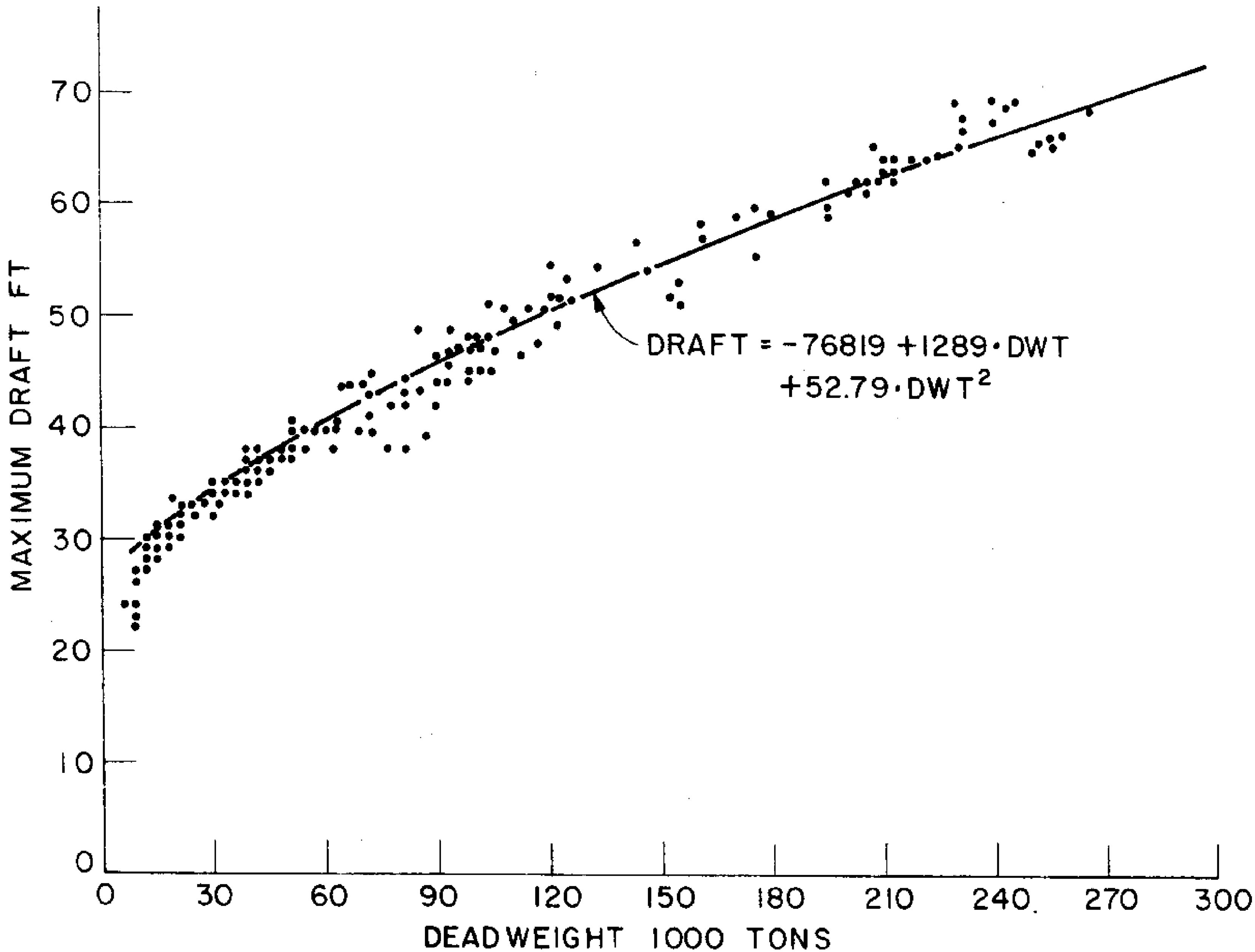

FIGURE I.2.3. SCATTER DIAGRAM OF DRAFT VS DEADWEIGHT
SOURCE: HUNTER (1969)

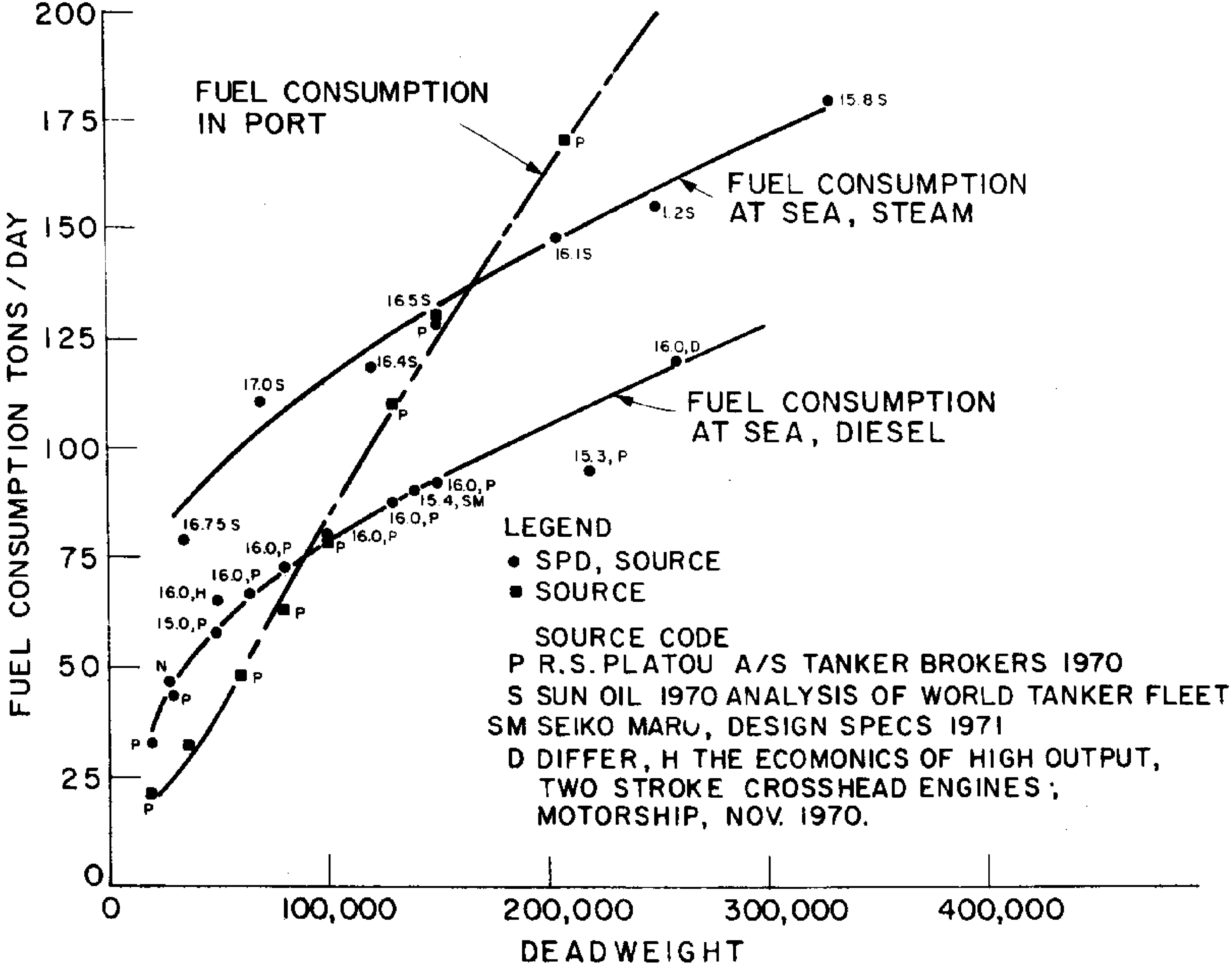

FIGURE I.2.4 FUEL CONSUMPTION VS DEADWEIGHT TANKERS

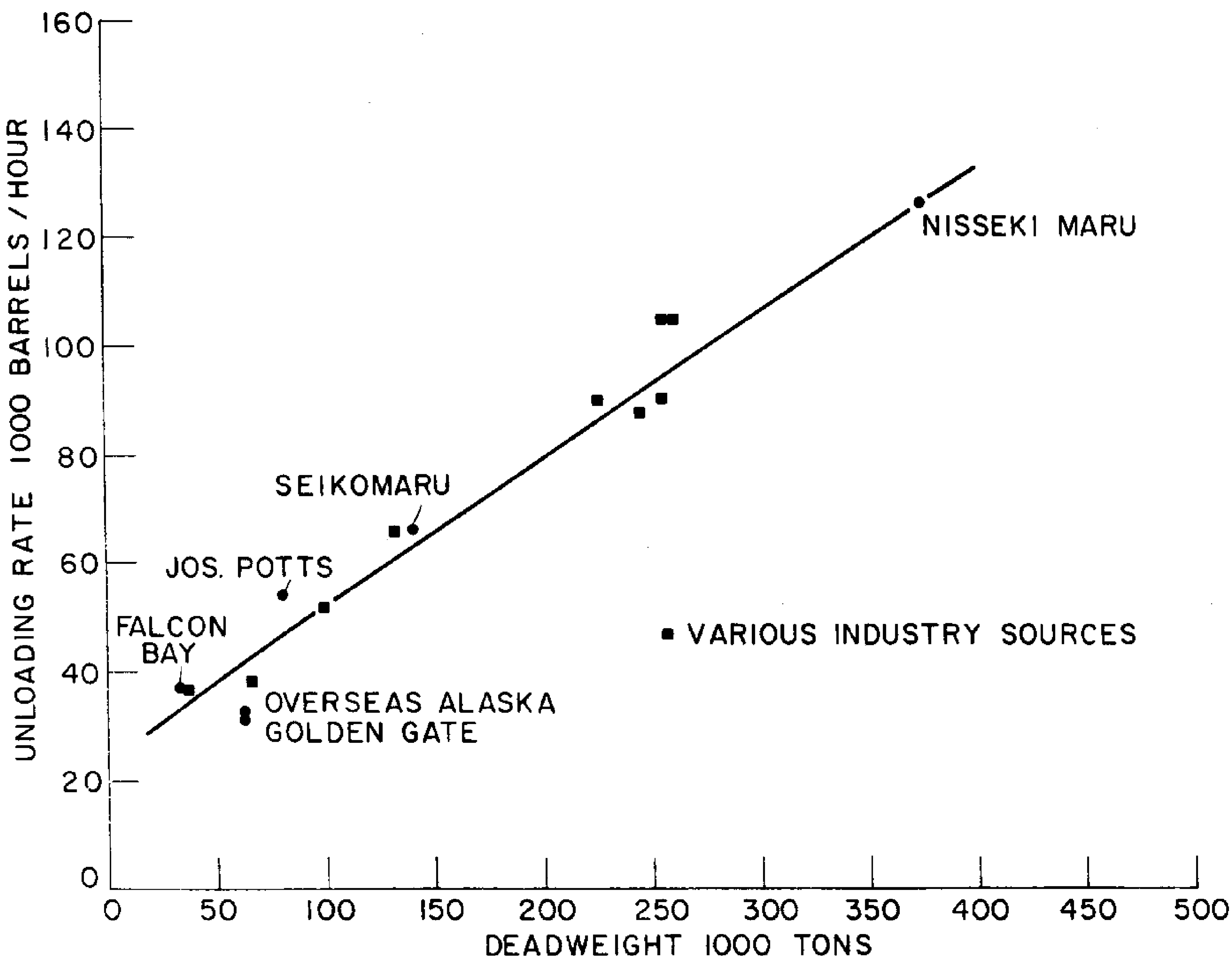

FIGURE I.2.5 LOADING & UNLOADING RATE

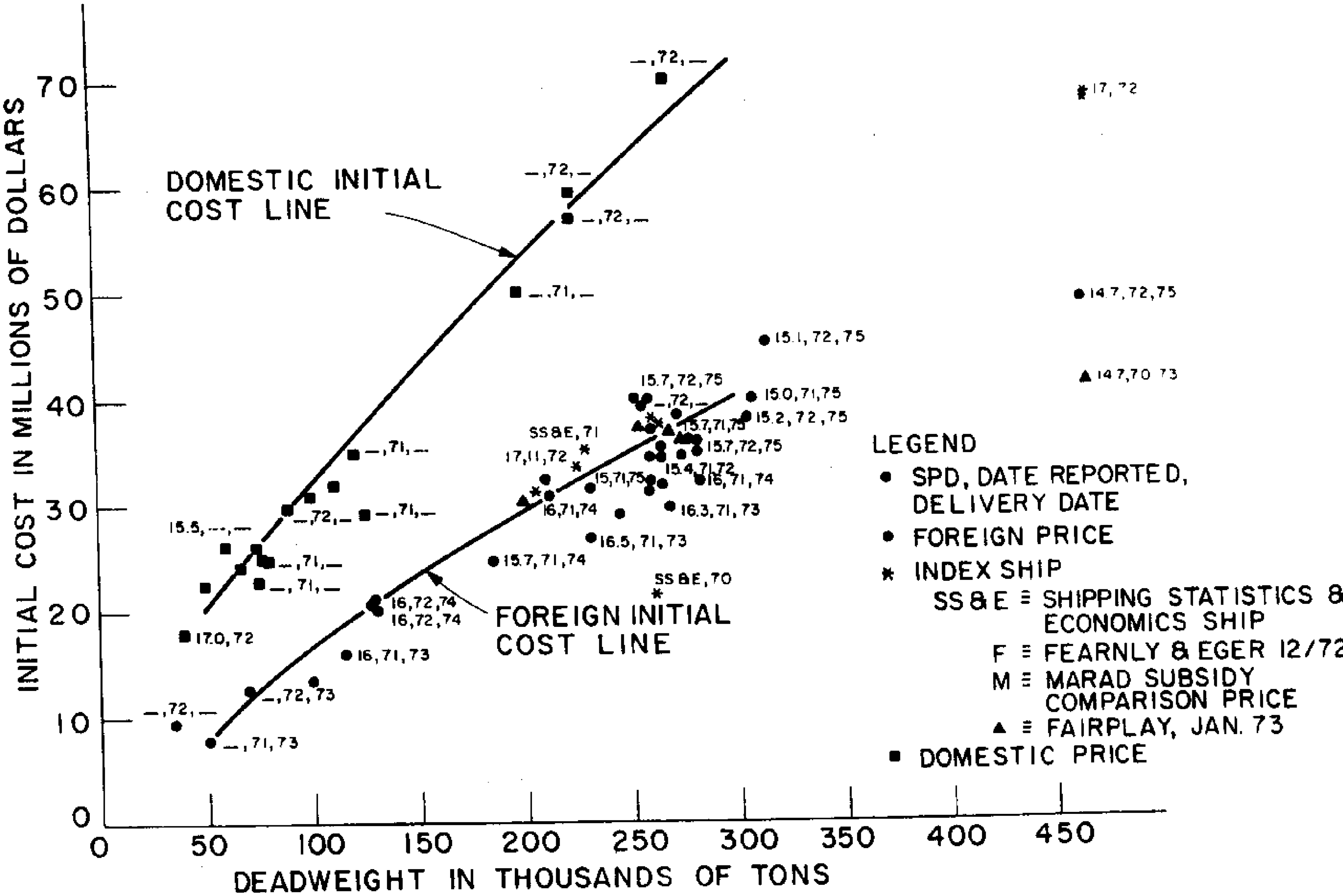

FIGURE I.2.6 TANKER INITIAL COST VS DEADWEIGHT

Western European-Japanese crew. Use of a low wage rate crew (e.g. Spanish officers - Chinese men) could cut crew costs by a factor of two. It is likely that in the future, any rise in real wage rates will be matched by a decrease in crew size. All the expenses in Table I.2.1 represent generous estimates of 1972 outlays. When in doubt, we have tended to err on the high side. In the runs in this report, ship life has been set at 20 years and operating days per year at 345. The tanker fleet has been averaging about 17 days off hire per year in recent years (Fearnley & Egers, 1972).

It is important both to an understanding of Figure I.2.6 and, more basically, to tanker transport in general to realize that the market price of tanker services, the charter rate, and to a larger degree the initial bid prices of tankers, exhibit a highly cyclic behavior. The market for tanker services is one of the purest examples of competition existing.* Due to uncertainty concerning future ton-mile demand and a tendency for shipowners to increase new ship orders when rates are high and decrease them when rates are low, the charter rate alternates between periods when the rate is well below the price required to return the average shipowner his cost of capital and periods where the rate is well above this price. That is, part of the time he is losing money and part of the time he is making a great deal of money. The typical pattern is an extended period (5 years or more) of low rates followed by a relatively brief period (perhaps 1 year) of extremely high rates. The fluctuation in rates from bottom to top can be a factor of five or more. However, over the long run, in order to establish a quasi-equilibrium with respect to capital flowing into

*In this context, we are using the economists' definition of competition: no individual buyer or seller has the power to set rates. For a more detailed definition, see Chapter I.3.

Table I.2.1

Values Used in EXCRUDE Runs

DWT	Crew Costs	Insurance	Maintenance	Administration & Regulation
50,000	350	190	250	200
100,000	360	290	275	200
150,000	370	430	300	200
200,000	380	530	325	200
250,000	390	670	350	200
300,000	400	790	375	200
350,000	410	910	400	200
400,000	420	1,010	425	200
450,000	430	1,090	450	200
500,000	440	1,190	475	200

Ship life = 20 years
Fuel price = $18/ton (includes lube, oil)
Operating days = 345
Pilotage = $44 per ft of draft per visit
Towage = $1,600 per visit

	Draft Limit	Lost Time Days	Towage
Persian Gulf	100'	.25	3,200
Present Delaware	41'	.85	3,200
65' Delaware	65'	.25	3,200
Pt. Tupper	65'	.25	3,200
Machiasport	65'	.25	3,200

Table I.2.1.
Crew cost, insurance, maintenance, and administration & regulation are listed in yearly cost in thousands of dollars.

tanker ownership, the average of these rate fluctuations must be such that the average owner just makes his opportunity cost of capital plus perhaps a small premium for the risks he takes. Of course, this average is made up of some owners who make enormous sums of money and some who go bankrupt, depending on how well they time their investment and chartering decisions. But studies of the tanker market (Devanney, 1971) point to the fact that taking the average over the long run and over all owners, oil companies as well as independents, tanker investors earn little more than the cost of their capital. This is our justification for keeping the charter rate fixed at the price which would return the shipowner his cost of capital if maintained throughout the life of the ship. Of course, fluctuation in the actual charter rate will generate fluctuations in the actual price of landed oil. However, for our purposes, the average of these fluctuations is all we require.*

Returning to the question of initial costs, the fluctuations in charter rates (the price of transporting oil) induce fluctuation in the price of ships, for when the rates are up, owners will typically order three or four more times as much new tonnage as when the rates are down. This creates a seller's market in shipbuilding and the price of new ships rises. The reverse happens after the charter rates drop, with some lag. Thus, the real price of new ships can fluctuate by as much as 50% with these fluctuations in orders. Most of the quotes shown in

*Whenever there is a boom in tanker rates, proponents of the import quota quickly point out that, at that moment, domestic oil is no more costly than imported oil, also offering the boom in rates as evidence of the "instability" of foreign oil. New England should not be misled. The boom is a self-correcting sign of healthy competition. The rates will soon retreat to levels at which tanker transportation is a bargain. It is a purely economic phenomenon which has nothing to do with political instability.

Figure I.2.6 are from the period 1971-1972, when orders were up in response to the 1970-1971 boom. Thus, these prices represent an upper bound on the real cost of new tankers in 1972 dollars. This is the reason why our initial cost function is somewhat below some of the 1971-1972 quotes and somewhat above the earlier quotes. Once again we are after the long-run average.

For tax purposes, the ship is treated as if it is owned by an integrated American oil company and computation of American taxes is handled by the PROFIT routine rather than by EXCRUDE. Actually, it doesn't make too much difference, for neither the independent shipowner under a flag of convenience nor the integrated oil company pays very much in the way of American income taxes, as we shall see.

EXCRUDE has the ability to handle both shoreside and nearshore fixed unloading terminals and offshore single-point mooring (SBM)-based terminals. In the runs analysed in this report, the present Delaware and 65' Delaware terminals are assumed to be nearshore fixed platforms, the Pt. Tupper, Machiasport, and Dighton terminals are assumed to be SBM-based.* For these runs, the cost figures used are shown in Table I.2.2. These figures do not include crude storage, which is handled by the refinery package.

The assumption with respect to present Delaware is that the outlays for fixed facility are sunk costs. This is biased in favor of present Delaware since some expansion would be required for the future. The 65' Delaware option is based on dredging to nearshore fixed facilities costing nine million dollars apiece

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*Actually, Pt. Tupper and Machiasport terminals might very likely have fixed shoreside facilities. But according to our cost figures, the SBM system is slightly cheaper. Therefore, in order to make a more direct comparison with the Dighton case, we have chosen to run the offshore terminals.

Table I.2.2
Terminal Cost Assumptions
All Figures in Millions of Dollars

	Initial Cost	Annual Operating Cost
Present Delaware	—	.25·N
65' Delaware	18 + 9·N	.25·N
Pt. Tupper	10 + 2·N + 1.5 mi pipeline to shore	.6 + .14N
Machiasport	10 + 2·N + 2 mi pipeline to shore	.6 + .14N
Dighton	10 + 2·N + 36 mi pipeline to shore	.6 + .14N

N = number of berths required (based on mooring time of 4 hours and a utilization factor of .3).*

*Source for utilization factor: Lind, 1972.

The dredging costs assumed are roughly one-third of the actual estimated cost of dredging a 70 ft channel representing an allocation of channel costs on the basis of New England's percentage of the East Coast market. The last three terminals are based on offshore single-point moorings in 72 ft of water.

Crude is pumped ashore from a fixed pumping platform. For the Dighton case, another pumping station pumps the crude 26 miles overland to Dighton. To handle the throughput increase through time, a series of parallel lines are laid. The first line is designed to the throughput which will exist in the tenth year of the project. Every ten years thereafter a new line is laid based on the increase in throughput which will occur through the next ten years. This is not necessarily an optimal pipeline expansion strategy but it will serve to give us a reasonable estimate of the overall pipeline cost.

At each ten-year expansion point, pipeline size and pumping power in each link is chosen by considering a range of pipeline diameters running from 6" to 42". For each such diameter the required pumping power is computed. That combination of diameter and pumping power which results in the lowest present value cost over the ten-year period is chosen. Pipeline system costs and design criteria used are listed in Table I.2.3.

The initial cost of the offshore pumping platform and risers is set at ten million dollars. This does not include the pumps themselves. In addition, one SBM for every 160 vessel arrivals per year is set.(Lind 1972). The incremental cost of each SBM mooring is put at 2 million dollars. Data offered in Section I.2.5 indicates that ten million dollars would easily cover the cost of a very large platform in semi-protected waters of 72 ft depth. The actual cost of SBM's themselves has been running at between one and one and a half million dollars (Bloch 1971). Operating costs for the offshore terminal have been put at $600,000 based on a crew of 20 working standard offshore (weekly) shifts and unassisted mooring.* The per-berth annual costs of $144,000 are based on Interconsult (1972).

It really doesn't make too much difference what we assume about the cost of unloading terminals for they all generally end up costing 3¢/barrel handled or less.

Table I.2.3
Pipeline Cost and Design Criteria

Pipe yield stress	56,000 psi
Safety factor on land	1.75 (based on heavily populated area)
Safety factor at sea	2.00
Max. thickness allowed	.75"
Right of way cost on land	$10/ft (max. value observed in recent literature)
Pumping power cost	"$75/PH, $150/HP offshore"

Pipeline cost:

Diameter	Cost Under Water/Mi	Cost On Land/Mi
6"	120,000	65,000
8"	150,000	70,000
10"	180,000	77,000
12"	230,000	85,000
16"	240,000	90,000
20"	280,000	111,000
26"	350,000	135,000
30"	430,000	150,000
32"	500,000	160,000
36"	700,000	165,000
42"	1,000,000	185,000

Pumping power requirements were calculated from the Modified Panhandle equation in the case of natural gas transmission and Miller's equation in the case of crude oil and other petroleum liquids. In both cases ambient temperature was taken as 60°F. (Campbell, 1970)

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*Most present SBM terminals are based on launch-assisted mooring. This involves an expense of at least $250,000 per year and limits mooring to wave heights of about 6 feet or less. Phillips at Ekofisk has developed an unassisted system whereby with minor modifications to the tanker, they successfully moor in 14 ft seas and 35 knots and need not unmoor until waves are near 20 ft or winds greater than 40 knots. The only aid given the tanker is occasionally a diver is used to stream the mooring line. This has been verified by our on-site visit.

Table I.2.4 summarizes the EXCRUDE results for the set of variable values used in this report. Under the assumptions we have employed, the decrease in investor's landed cost resulting from moving from present East Coast draft limitations to a port capable of handling a 65' draft tanker is about 30¢ per barrel. Notice the sharp rise in present valued f.o.b. cost of crude under the assumption of escaled payments to exporting countries.

The EXCRUDE routine is also used to compute the landed cost of imported residual fuel. The resid is assumed to cost $3.10 per barrel in Venezuela before escalation. The cost of transporting this oil to the region depends on the products distribution system employed. If there is a deepwater terminal within the region, then draft constraints at the loading port (set at 45') are limiting. Otherwise draft constraints in the products reception ports determine the resid tanker size. EXCRUDE estimates the cost of resid transport from Venezuela at 20¢ per barrel at 8% and 26 cents at 15% assuming present products distribution system, and at 18¢ and 23¢ assuming a deepwater terminal within the region.

Table I.2.4

Some EXCRUDE Results

UNIT PRESENT VALUED COST OF FOREIGN CRUDE f.o.b.

Cost of Capital	8%	15%
No escalation	$1.65	$1.65
Escalation	$4.15	$4.12

CRUDE TRANSPORT SYSTEM FOR 4% CONSUMPTION GROWTH

	Transport Cost		Tanker	Number of Arrivals	
	8%	15%	Size	1978	2011
Pres. Del.	.98	1.24	65,000	1,080	3,930
65' Del.	.69	.92	230,000	290	1,050
Pt. Tupper	.67	.89	230,000	290	1,050
Machias.	.68	.90	230,000	290	1,050
Dighton	.68	.90	230,000	290	1,050

CRUDE TRANSPORT SYSTEM FOR 2% CONSUMPTION GROWTH

	Transport Cost		Tanker	Number of Arrivals	
	8%	15%	Size	1978	2011
Pres. Del.	.98	1.24	65,000	925	1,772
65' Del.	.69	.92	230,000	250	470
Pt. Tupper	.67	.89	230,000	250	470
Machias.	.68	.90	230,000	250	470
Dighton	.68	.90	230,000	250	470

I.2.3 The refinery package

The refinery package (REFINE2) is employed to compute the present value investor costs associated with refinery crude oil into various products. The refinery model is based on W. L. Nelson's model for crude oil realization (Nelson, 1970). The basic model examines the laboratory analysis of a particular crude oil and then determines the product mix which may be obtained from this crude. The product mix determines the complexity of the refinery. Complexity, in Nelson's terms, is an index which reflects the degree of sophistication of the equipment required to produce the particular product mix. (For example, the production of gasoline requires considerably greater treatment of crude stocks than the production of No. 2 distillate.) Empirical evidence indicates a strong correlation between the complexity index and capital/operating costs of refineries.

Nelson's data is based on a 30,000 bbl/day refinery. This is an extremely small plant by our standards. The refinery package scales the capital and operating costs according to the curves given in Figures I.2.7 and I.2.8., to take into consideration the economies of scale inherent in large refinery capacity. Notice that there is very little economies of scale associated with refineries of greater than about 250,000 bbl/day (Gilliland, 1972). In addition, the package adds costs associated with (a) the reduction of tetraethyl lead (TEL) in the output gasoline, (b) desulphurization of fuel oil products, and (c) effluent treatment.

Of all the cost packages in the program, REFINE2 is subject to the greatest possible error in cost estimation. This is due to the following reasons:

1) Nelson's original data was based on worldwide averages. World averages are quite different from U.S. refinery practice. (e.g. the average

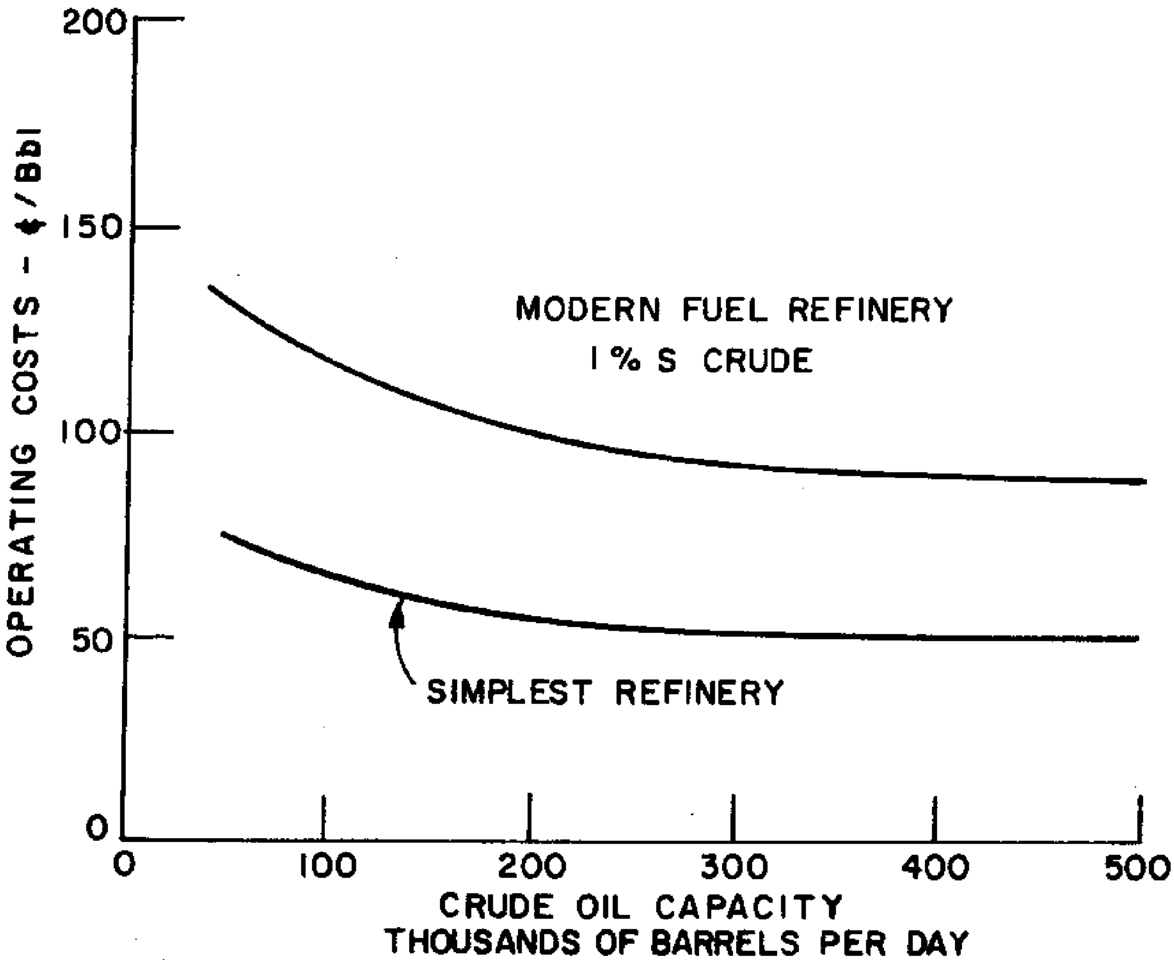

FIGURE I.2.8 OPERATING COSTS

U.S. refinery produces nearly twice as much gasoline as a European refinery)

2) The Nelson model is not dependent on demand. The product mix determined is solely a function of crude analysis and the world price structure for products in the early 1960's.

3) Reduction of TEL, desulphurization, and, particularly, stringent effluent treatment are comparatively new processes in the refinery industry so that cost data is very difficult to obtain.

4) Construction and operating costs are based on 1972 levels. These levels reflect a strong trend towards automation; how long this trend will continue before reaching a steady state is purely speculative.

The fact that Nelson's model was based on empirical data for world refineries is potentially a serious drawback because U.S. refineries tend to produce different product mixes than these averages (e.g. any kerosene with a smoke point of 18 would be produced for the world market while in the U.S. only high-quality kerosene with smoke points of 21 or better is produced.) One possible solution is to artificially alter the criteria by which the product mix is produced. The potential error here is that such an approach ignores added expenses incurred by additional processing of lower quality stocks to produce acceptable output product quality. This is probably not a significant cost except in the production of gasoline, particularly through hydrotreating.

For purposes of this project, a dummy crude was employed which would yield the proper product mix for New England (with or without residual fuel oil: Table I.2.5.) from the Nelson model analysis. Because this

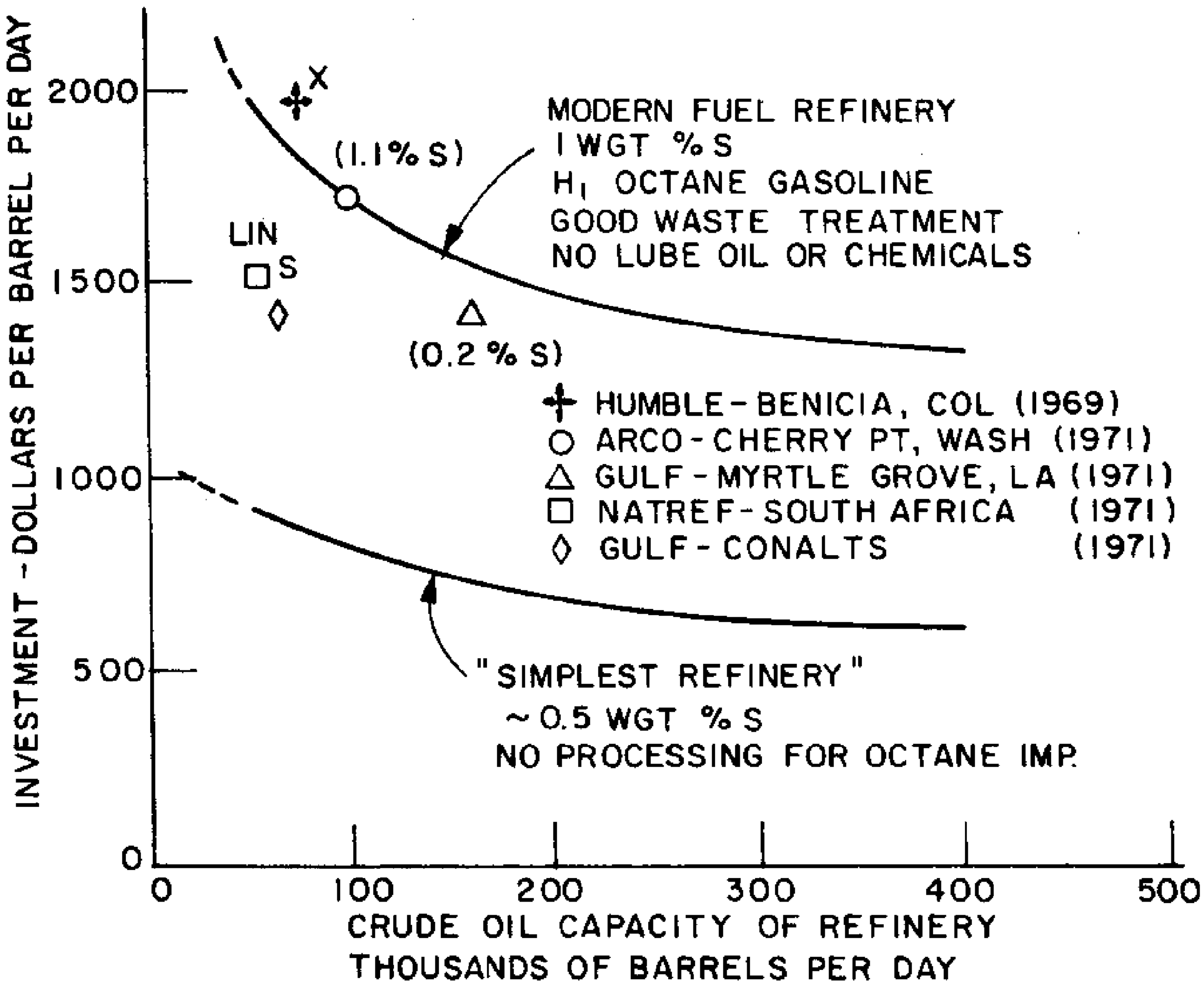

FIGURE I.2.7 REFINERY INVESTMENT COSTS

Table I.2.5
Product Mix Used in New England Demand Analysis

	All New England	No Resid
Gasoline	28.90%	45.60%
Kerosene/Jet	6.00	6.40
Distillate oil	13.25	22.00
Diesel	13.25	22.00
Residual oil	34.60	0.00
Refinery fuel	4.00	4.00
Total	100.00%	100.00%

Table I.2.6
Effluent Contamination Standards

pH	7 to 8.5
Total oils	15 ppm max
Phenols	0.2 ppm max
Sulfides	0.5 ppm max
Mercaptans	0.5 ppm max
Ammonia	0.25 ppm max

mix involves a higher proportion of distilled products than the worldwide average, REFINE2 compensates by increasing the overall complexity index by 15.0% to partially recover the costs of additional processing.

The lack of demand dependence introduces an error in a similar way as the use of world averages. Presumably, if the price of a particular product increases, the refiner might be interested in incurring some additional costs to produce more of this product. By introducing dummy crudes to satisfy New England demand, some additional costs above and beyond those of the Nelson model may well be introduced when a real crude is processed. The 15.0% increase in complexity index is also intended to cover this possibility.

To establish costs for TEL reduction, desulphurization, and effluent treatment (which are only sparingly treated by Nelson), a literature survey was performed to gather background data. Because these are relatively recent processes in the industry, very little data is available. What data is available is very difficult to generalize upon since it is in the form of specific cases applying particular processes to discrete throughputs of unique crudes. Synthesis of this data into a simple algorithm for estimating costs is very difficult.

The added cost of octane upgrading without TEL, by means of cracking and reforming, is estimated from the curves in Figures I.2.9 and I.2.10. For desulphurization, it is assumed that the treatment will be some variety of hydrocracking. The curves used for desulphurizing costs are shown in Figures I.2.11 and I.2.12. They have the form

$$\text{COST} = (S_r - S_f)(A + \frac{B}{S_f})$$

where S_r is the percent sulphur in the residual fuel stock, S_f is the percent sulphur in the fuel oil product, and A and B are constants (for capital costs A=50, B=60; for operating costs A=15.2, B=3.1). All these curves are our

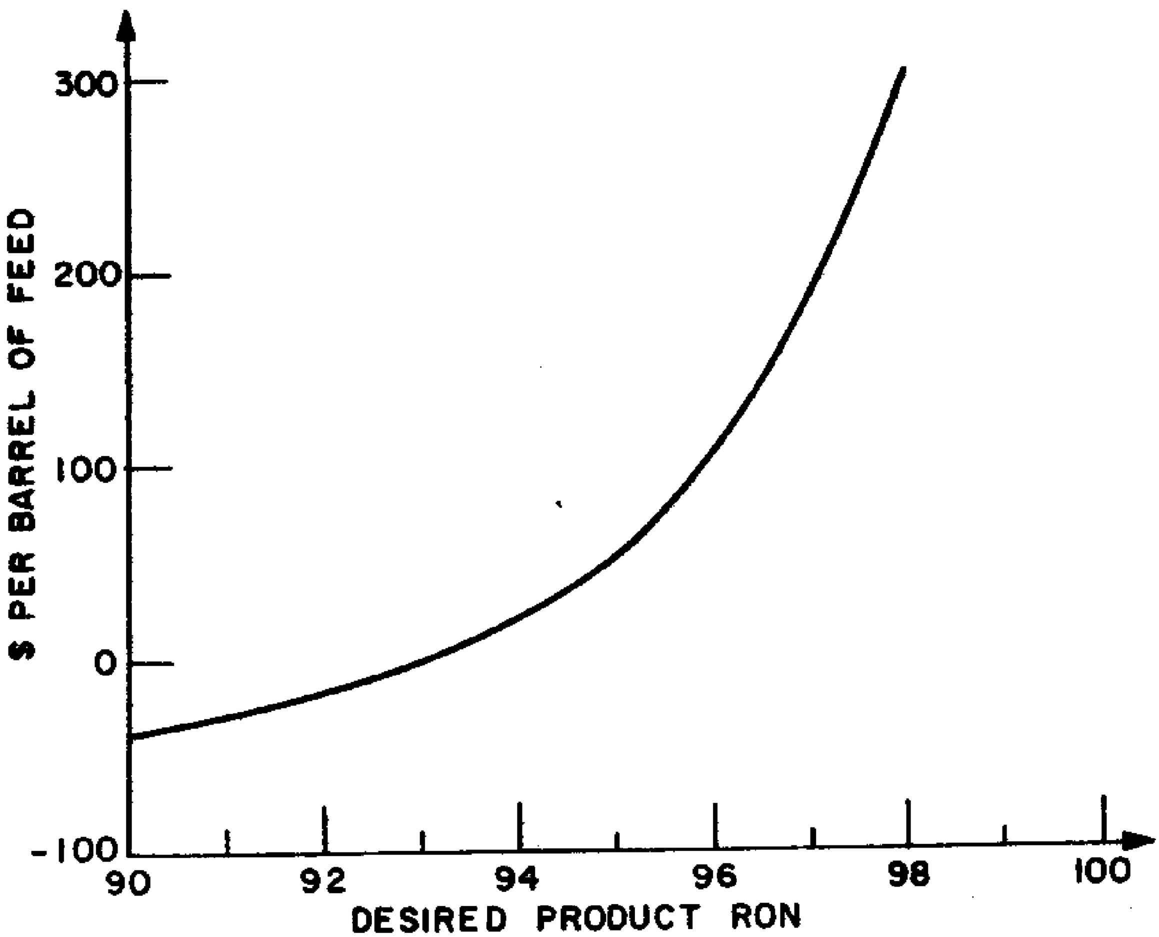

FIGURE I.2.9 INCREMENTAL INVESTMENT COSTS FOR OCTANE UPGRADING

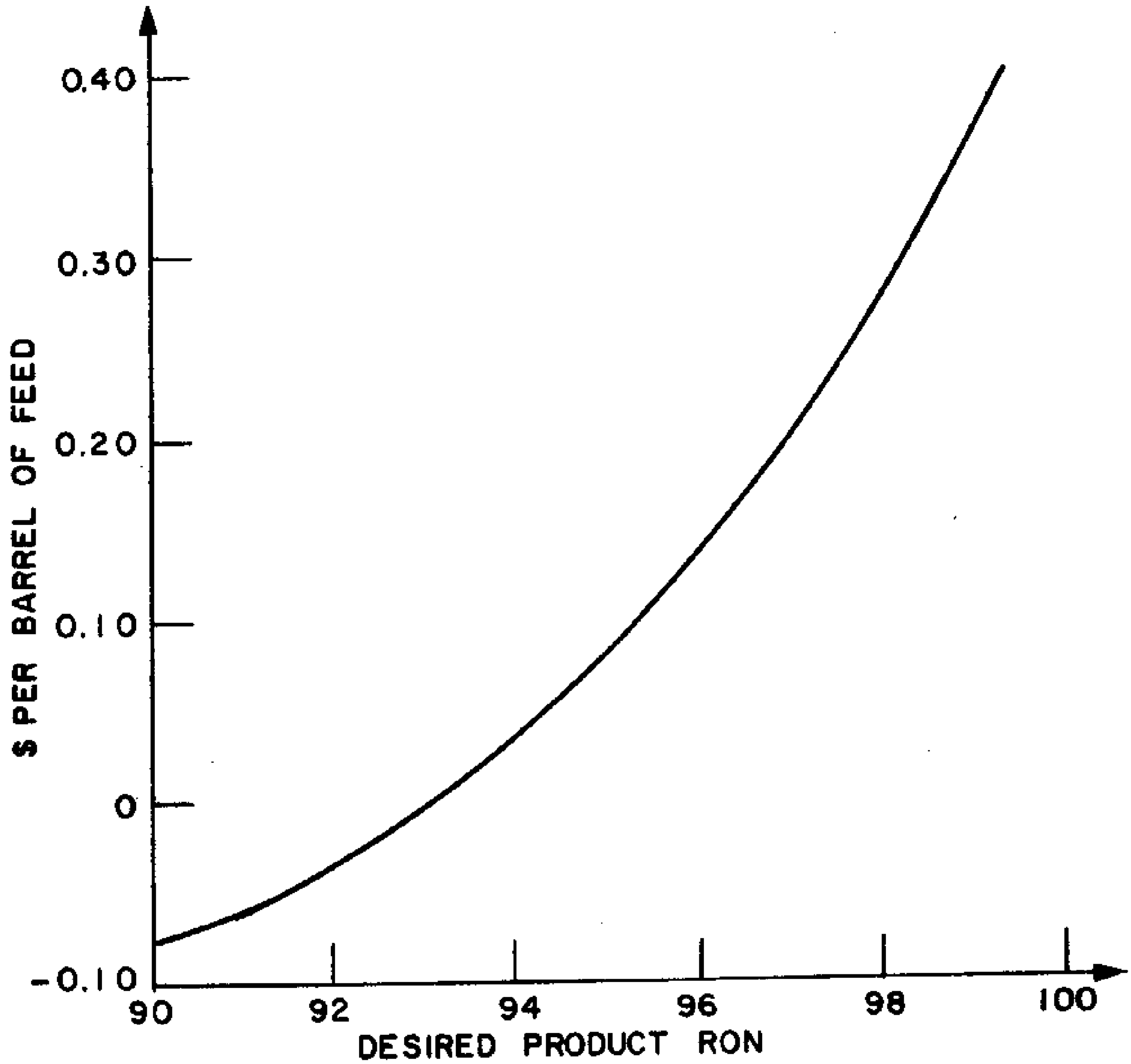

FIGURE I.2.10 INCREMENTAL OPERATING COSTS FOR OCTANE UPGRADING

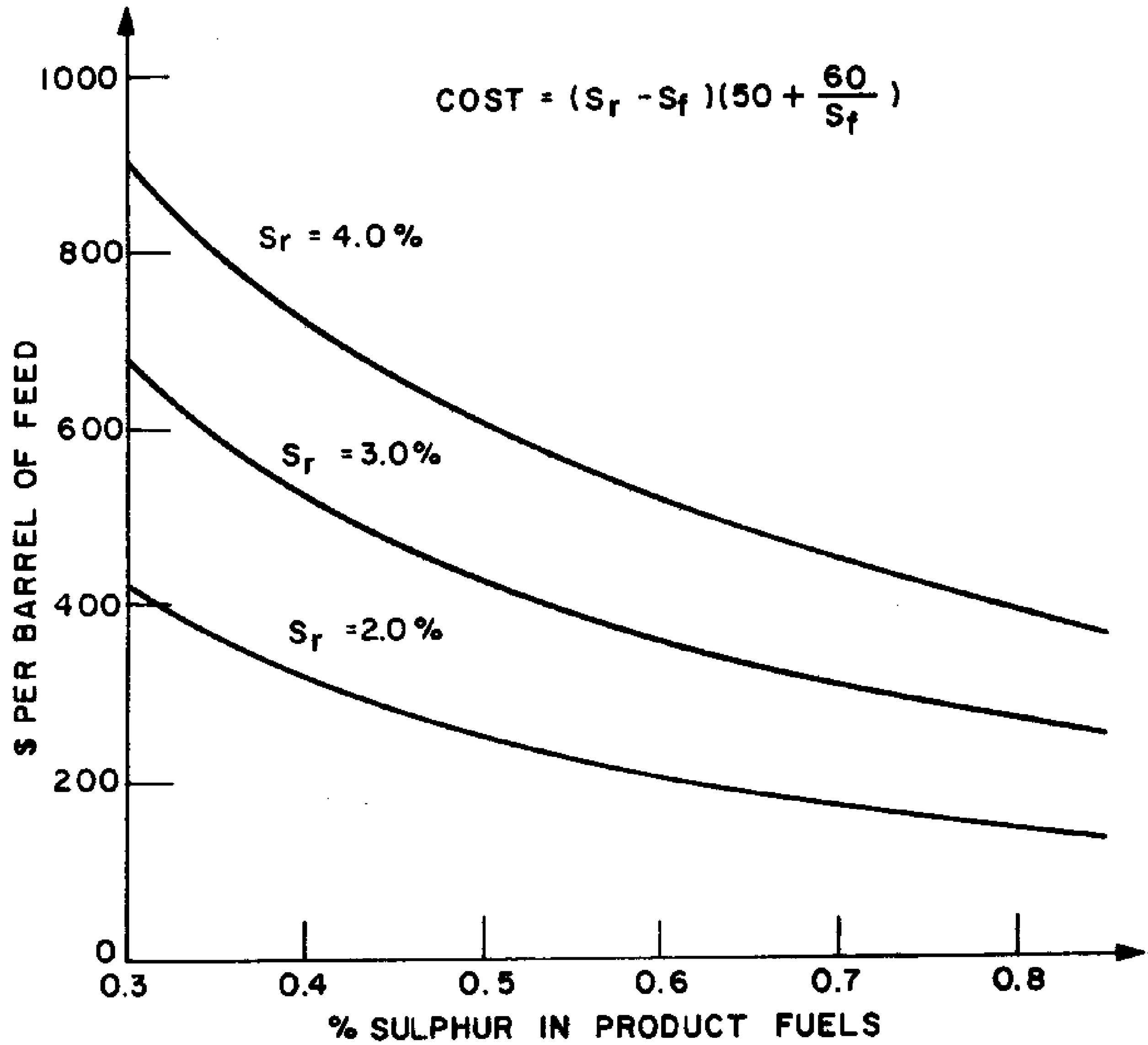

FIGURE I.2.11 INCREMENTAL INVESTMENT COSTS FOR DESULPHURIZATION

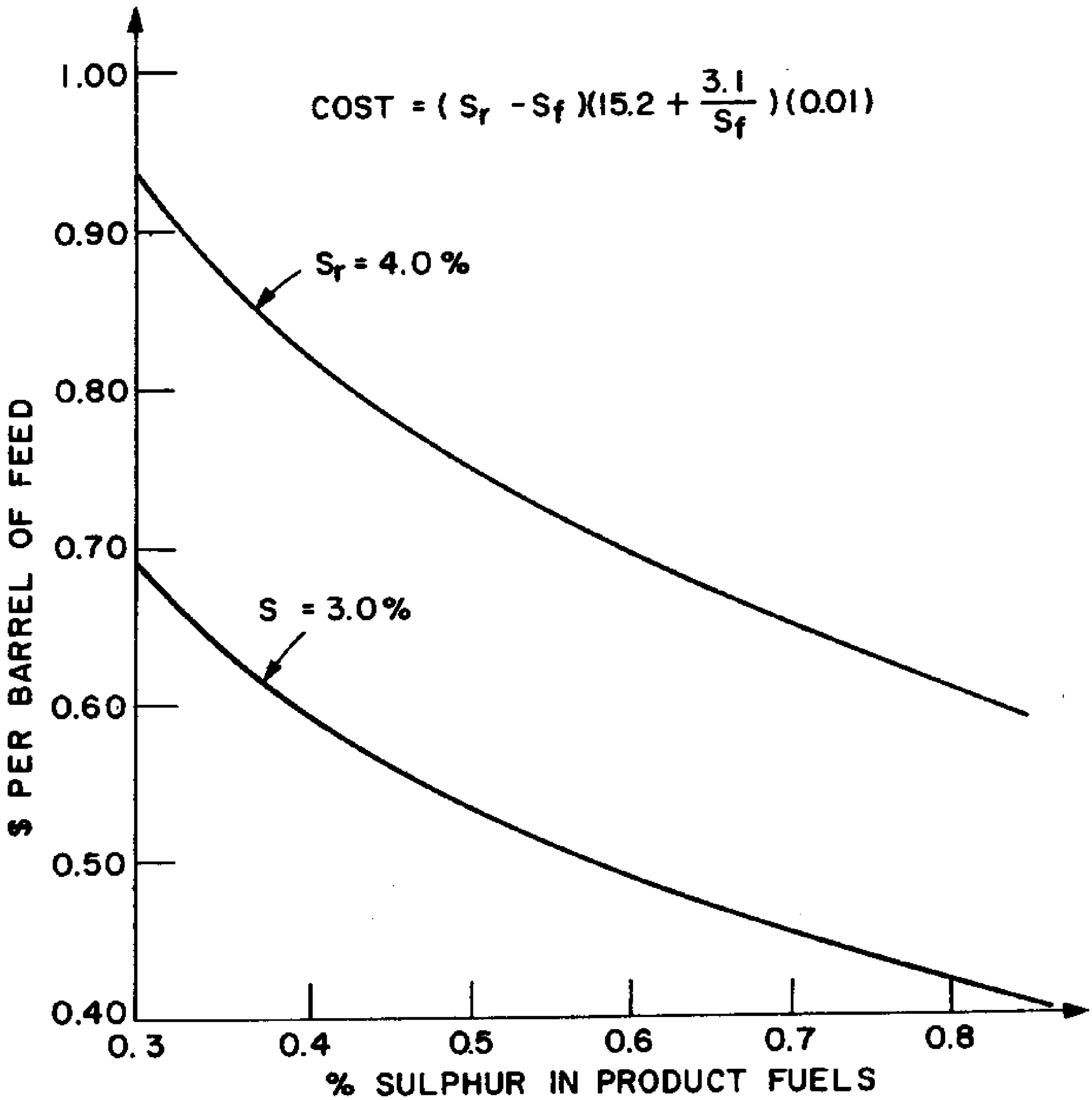

FIGURE I. 2. 12 INCREMENTAL OPERATING COSTS FOR DESULPHURIZATION attempt at synthesizing the available data which is displayed at points on the figures. In general, the accuracy of these curves is probably on the order of ±15.0%.

Effluent treatment is an even more difficult problem due to the paucity of data and the fact that such costs are extremely nonlinear. To remove the last few parts per million of undesirable materials from the refinery effluents could easily cost many times that required to remove the first few thousand parts per million. Current standards for a very "clean" refinery are given in Table I.2.6. For purposes of most of the runs employed in this project, it was assumed that a New England refinery would be required by 1978 to produce effluents of this quality. Based on discussions with industry personnel, REFINE2 associates an added cost of 10% of total refinery investment to achieve this level of treatment. The error in this estimate may be on the order of ±50.0%.

While the margin for error for octane upgrading, desulphurization, and effluent treatment cost estimates is large, the effect on total refinery cost is relatively small. Since each of these processes would be unlikely to amount to more than 10% of total investment, they would have an effect of 11% error on total refinery cost estimate if combined together in the worst possible way. In addition, errors in cost estimate for one process may compensate for errors in others. For example, when desulphurization costs are considered, the removal of sulphur (as an effluent) and an overlapping of cracking with octane upgrading may, in reality, serve to reduce total added costs for these processes.

Since 1956, construction costs in the refinery industry have risen 250.0% while operating costs have risen only 20.0%. These figures represent a steady trend towards automation and a strong desire of U.S. operators to produce gasoline (requiring complex processing) at the expense of residual fuel oils (requiring minimal processing), due at least in part to the fact that resid does not come under the import quota, while the lighter products do. It is unlikely that these divergent trends can persist in the future. Unfortunately, however, it is extremely difficult to estimate at what level the current dynamic situation will reach a steady state, so REFINE2 assumes 1972 levels of capital and operating costs rather than engaging in speculation on the future.

Though the refinery package is inherently less accurate in its estimates of costs than the other packages in the program, this is not so serious a problem as it might first appear. The costs generated for the refinery processing are the same for each case considered irrespective of refinery locale. For most of the cases considered in this report, refinery costs are simply a function of crude input and New England product mix. Thus, for purposes of comparing one strategy to another, inaccuracies in total cost are cancelled. The refinery package is the only one which is independent of the detailed inputs for a particular case. The only situation for which this cancellation does not occur is the comparison between cases involving the NO RESID refinery output option and the ALL NEW ENGLAND output option - a comparison which we will make very limited and circumspect use of in the sequel.

I.2.3.1 Specific package structure

REFINE2 takes as input crude volume (through time), a laboratory analysis of the crude oil, an indicator for whether TEL in gasoline will be allowed, output gasoline octane number, acceptable fuel oil sulphur content, an indicator for whether the refinery will be run by a major oil company or an independent, and an indicator for the level of effluent treatment as inputs. The crude analysis is examined and a product mix is determined. From the product mix the refinery complexity index is computed. From the complexity index, base capital and operating costs are determined. These base costs are then scaled for the volume crude throughput to obtain overall capital and operating costs for a particular size of refinery. Then additional capital and operating costs are determined for octane upgrading, desulphurization, and effluent treatment, where applicable.

When there is a volume increase from one year to the next, it is assumed that a new, separate, and complete refinery will be built to handle exactly this increase. This is something of an oversimplification since real refineries would probably anticipate growth in their original designs and would build additional capacity at discrete intervals of greater than a year (running somewhat under capacity occasionally) in order to maximize overall profits. The effects of such machinations should, however, be small and the error on the part of REFINE2 will be towards higher outlay cost.

Examples of how the refinery costs vary according to crude analysis are given in Tables I.2.7 through I.2.8. In this report dummy crudes were employed to reflect New England product mix. The refinery outputs for this mix, with and without residual fuel oil output, are given in Table I.2.5. These product mixes assume that 4.0% of the total crude input will be used as internal fuel oil and that all gases, whether dissolved in the crude or produced as byproducts of distillation, cracking, and reforming will also be used as refinery fuel.

The actual crude assumed in the NO RESID runs presented in this report has an API gravity of 34°, a sulphur content of 1.76% and straight run gasoline yield of 32%. The straight run octane rating is 49. This gasoline is upgraded to 93 octane rating. No tetraethyl lead is allowed in the upgrading procedure. The effluent standards of Table I.2.6 are assumed. The resulting per barrel costs of refining for the NO RESID option are given by Table I.2.10.

Table I.2.7
Example of Refinery Costs
Developed by Model

<u>Refinery data</u>:	
On line	1977
Capacity	500,000 bpd
<u>Options</u>:	
TEL	NONE
Fuel oil sulphur content	0.5%
Cleanup	EXTRA
<u>Input data</u>:	
Location	Bachaquero, Venezuela
API	14%
Sulphur content	2.64%
Characterization factor at 550°F	11.15
Characterization factor at 750°F	11.30
Percent kerosene	7.0
Kerosene API	35°
Kerosene smoke point	16.0
Percent sulphur in kerosene	0.56
Straight run gasoline (percent)	5.0
S.R. gasoline octane number	68
Percent diesel	22.5
Diesel pour point	-35.0°F
Diesel index	33.0
Percent boiling under 550°F	15.0
Percent wax or low cold test stock	19.0
Percent boiling 400°900°F	41.5
Lube pour point	-10.0°F
Lube viscosity index	-17.0
Processing loss (percent)	0.5
Asphalt quality	EXCELLENT
Asphalt quantity	53.5
Percent mercaptans	0.03

Table I.2.7
(cont.)

Output mix (percent of crude input):	
SR gasoline	5.00
Cracked gasoline	18.58
Total gasoline	23.58
Kerosene	0.00
Diesel	0.00
No. 2 distillate	10.00
No. 3 distillate	5.51
Wax	0.00
LCT lube	0.00
Lube, grade A	0.00
Lube, grade B	0.00
Lube, grade C	0.00
Lube, grade D	0.00
Asphalt	7.84
Total distilled products	46.94
Loss	2.36
Residual fuels	50.70
Resulting costs:	
Basic operating cost	$110 million
Basic unit operating cost	0.95
Basic capital cost	569 million
Basic unit capital cost	1865 pdb
PV base refinery (scaled to size, 1972) cost	743 million
PV base refinery unit cost	1.08
Unit cost of TEL	NONE
Desulphurizing capital costs	203 million
Desulphurizing operating costs	39 million
PV desulphurizing unit costs	0.34
Cleanup capital costs	39 million
Cleanup operating costs	3 million
PV cleanup unit costs	0.04
Total present value cost of refining	1.16 billion
PV total unit cost of refining	1.67

Table I.2.8
Example of Refinery Costs
Developed by Model

Refinery data:	
On line	1977
Capacity	500,000 bpd
Options:	
TEL	NONE
Fuel oil sulphur content	0.5%
Cleanup	EXTRA
Input data:	
Location	Los Manueles, Venezuela
API	32.7°
Sulphur content	0.86%
Characterization factor at 550°F	11.85
Characterization factor at 750°F	12.10
Percent kerosene	11.9
Kerosene API	42.6
Kerosene smoke point	22.6
Percent sulphur in kerosene	0.12
Straight run gasoline (percent)	27.6
S.R. gasoline octane number	50
Percent diesel	26.1
Diesel pour point	5.0
Diesel index	57.0
Percent boiling under 550°F	40.3
Percent wax or low cold test stock	25.9
Percent boiling 400°-900°F	52.0
Lube pour point	105
Lube viscosity index	100
Processing loss (percent)	0.0
Asphalt quality	AVERAGE
Asphalt quantity	20.0
Percent mercaptans	0.0009

Table I.2.8
(cont.)

<u>Output mix (percent of crude input):</u>	
ST gasoline	27.22
Cracked gasoline	21.67
Total gasoline	46.89
Kerosene	11.90
Diesel	0.00
No. 2 distillate	3.18
No. 3 distillate	6.07
Wax	0.00
LCT lube	0.00
Lube, grade A	0.00
Lube, grade B	0.00
Lube, grade C	0.00
Lube, grade D	4.63
Asphalt	0.00
Total distilled products	72.66
Loss	2.17
Residual fuels	25.17
<u>Resulting costs:</u>	
Basic operating cost	$146 million
Basic unit operating cost	1.26
Basic capital cost	695 million
Basic unit capital cost	2277 pdb
PV base refinery (scaled to size, 1972) cost	951 million
PV base refinery unit cost	1.38
Unit cost of TEL	NONE
Desulphurizing capital costs	62 million
Desulphurizing operating costs	12 million
PV desulphurizing unit costs	0.11
Cleanup capital costs	38 million
Cleanup operating costs	3.1 million
PV cleanup unit costs	0.04
Total present value cost of refining	1.19 billion
PV total unit cost of refining	1.71

Table I.29
Example of Refinery Costs
Developed by Model

Refinery data:	
On line	1977
Capacity	500,000 bpd
Options:	
TEL	NONE
Fuel oil sulphur content	0.5%
Cleanup	EXTRA
Input data:	
Location	Luby, Texas
API	48.80°
Sulphur content	0.10%
Characterization factor at 550°F	11.68
Characterization factor at 750°F	11.73
Percent kerosene	11.30
Kerosene API	41.60
Kerosene smoke point	19.5
Percent sulphur in kerosene	0.2
Straight run gasoline (percent)	59.5
S.R. gasoline octane number	53
Percent diesel	29.6
Diesel pour point	0.0
Diesel index	52.0
Percent boiling under 550°F	78.8
Percent wax or low cold test stock	6.0
Percent boiling 400°-900°F	35.6
Lube pour point	85.0
Lube viscosity index	59.0
Processing loss (percent)	2.9
Asphalt quality	GOOD
Asphalt quantity	2.0
Percent mercaptans	0.0003

Table I.2.9
(cont.)

<u>Output mix (percent of crude input):</u>	
SR gasoline	59.50
Cracked gasoline	3.36
Total gasoline	62.86
Kerosene	0.00
Diesel	29.60
No. 2 distillate	0.00
No. 3 distillate	1.05
Wax	0.00
LCT lube	0.00
Lube, grade A	0.00
Lube, brade B	0.00
Lube, grade C	0.00
Lube, grade D	0.00
Asphalt	0.00
Total distilled products	93.51
Loss	3.24
Residual fuels	3.25
<u>Resulting costs:</u>	
Basic operating cost	$159 million
Basic unit operating cost	1.36
Basic capital cost	740 million
Basic unit capital cost	2420 pdb
PV base refinery (scaled to size, 1972) cost	1.02 billion
PV base refinery unit cost	1.48
Unit cost of TEL	NONE
Desulphurizing capital costs	7.12 million
Desulphurizing operating costs	1.37 million
PV desulphurizing unit costs	0.01
Cleanup capital costs	37 million
Cleanup operating costs	3.2 million
PV cleanup unit costs	0.04
Total present value cost of refining	1.19 billion
PV total unit cost of refining	1.72

Table I.2.10

Refining Costs per Barrel - NO RESID

Cost of Capital	Consumption Growth Rate 2%	4%
8%	1.51	1.39
15%	1.68	1.65

The unit costs depend on the consumption growth rate. This is the result of our adding each year a facility for handling the next year's growth, which result is below effluent scale additions, especially for the 2% growth rate. This difference while artificial, need not concern us, for the 2% runs should be compared with other 2% runs and the 4% runs with other 4% runs. Refining costs are assumed to be independent of refining site. In general, the above costs are rather high for what is basically a simple fuel refinery--no lube oil, no petrochemicals, due primarily to the stringent gasoline requirements, the very low resid output, and the high level of effluent treatment assumed.

I.2.4 The products distribution package

I.2.4.1 Program structure and assumptions

The function of the products distribution package (PRODIST) is to develop and simulate the liquid petroleum transport system which a profit-maximizing investor would use to move petroleum products from a specified refinery to each of the eight major New England products reception ports. This program takes as input the consumption by year for each of four product classes: gasoline; kerosene and jet fuel; distillate and diesel fuel; and residual fuel oil, in each of eight New England ports (Searsport/Buckport, Portland, Portsmouth, Boston, New Bedford, Providence, New Haven, and Bridgeport) throughout the life of the project. In addition, the package has as inputs refinery location and capacity, refinery and discharge port draft limitations, the time the vessel is at reduced speed in the vicinity of loading and discharge ports, an indicator which specifies whether the discharge terminal is offshore, an indicator which specifies whether the nationality of the products carrier is foreign or domestic, and an indicator which specifies what combination of barges, tankers or pipelines are to be considered as candidates for the transport system. The program also has available to it in semi-permanent secondary storage tables of tanker, barge and pipeline specifications and cost for a variety of sizes, speeds and flags as well as terminal costs for both onshore and offshore terminals. The output of the program includes the particulars of the vessel system which it selects including size of vessel serving each port, number of such vessels through time and number of port calls per year through time as well as the present valued cost to the investor and to the nation of this system. For the Dighton refinery locale, the program prints out particulars on the selected pipeline system including pipe size and horsepower of each link and investor and national costs.

With respect to the vessel systems, the program considers each products reception port separately. Thus, there are no multiple-stop delivery routes. For each port, the package combines loading and unloading rates, fuel consumption at sea and in port, service speed, construction, crew, insurance, maintenance expenses for a range of combinations of vessel type (barge or tanker), and size within the draft limitations of the ports involved to obtain the overall cost of each such combination. Vessels are assumed to be chartered annually at a rate which would return the owner's cost of capital over a twenty-year life. After investigating all such combinations, the program selects that vessel type and size for that particular port pair which serves the link at minimum cost. It repeats this process for each products reception port. Thus, there will in general be a different ship or barge size for each discharge port. However, the vessel selected on a particular route is used throughout the life of the project. Only the number of vessels on that route will change with time, not their size.

I.2.4.2 Vessel cost assumptions

As presently constituted, for each refinery-products reception port link, the program considers tankers ranging from 20,000 to 300,000 tons and barges ranging from 20,000 to 40,000, ruling out, of course, any vessels which do not meet the draft limitation. Tanker speed is fixed at 15 knots and barge speed at 13 knots. While PRODIST has the capability of running foreign flag products carriers, no use of that capability is made in this report.* Hence the remainder of our discussion will be confined to American built and manned products carriers. Recent cost data on American products tankers is considerably sparser than that

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*Under present law and relaxation of the import quota, this is biased against Pt. Tupper.

for foreign crude carriers. What we have for tankers less than 60,000 tons is displayed in Figure I.2.13, which also shows the initial cost function assumed in this range. This curve corresponds reasonably well with 1/(1 - .43) times the foreign cost curve which agrees with the current 43% construction differential subsidy.

It should be remembered, however, that there is a wide variation in the cost per deadweight of products carriers depending on the degree of compartmentation (number of products the vessel can carry at one time), the flexibility of the piping system (to avoid contamination of one product by another), provision of cargo heating systems, and the corrosiveness of the chemicals it can handle. These costs are based on rather simple products carriers limited to handling four or five standard petroleum products with rudimentary anti-contamination measures.

Very few products carriers larger than 50,000 tons have been built. For this range, our costs are based on the domestic tanker cost curve of Figure I.2.6 arbitrarily raised by 20% to account for heating coils and additional piping.

Frankel (1972) has surveyed barge costs. The cost of a domestically built, oceangoing (notched stern) barge runs from 4.0 million dollars at 20,000 tons to 7.0 million dollars at 40,000 tons. A tug capable of pushing these barges at 13 knots will run from 4.0 million dollars (9,000 shp) to 6 million dollars (14,000 shp). The resulting initial costs are shown in Figure I.2.14, together with some recent designs. Industry sources have indicated that domestic tug-barge systems generally run about 30% cheaper than equivalent tanker systems (Ingram, 1971). Since our barges are two knots slower than our tankers, our curves are consistent with this statement. This differential is due largely to differences in classification society and Coast Guard regulations rather than any inherent advantage, for the tugs are rarely separated from their barges.

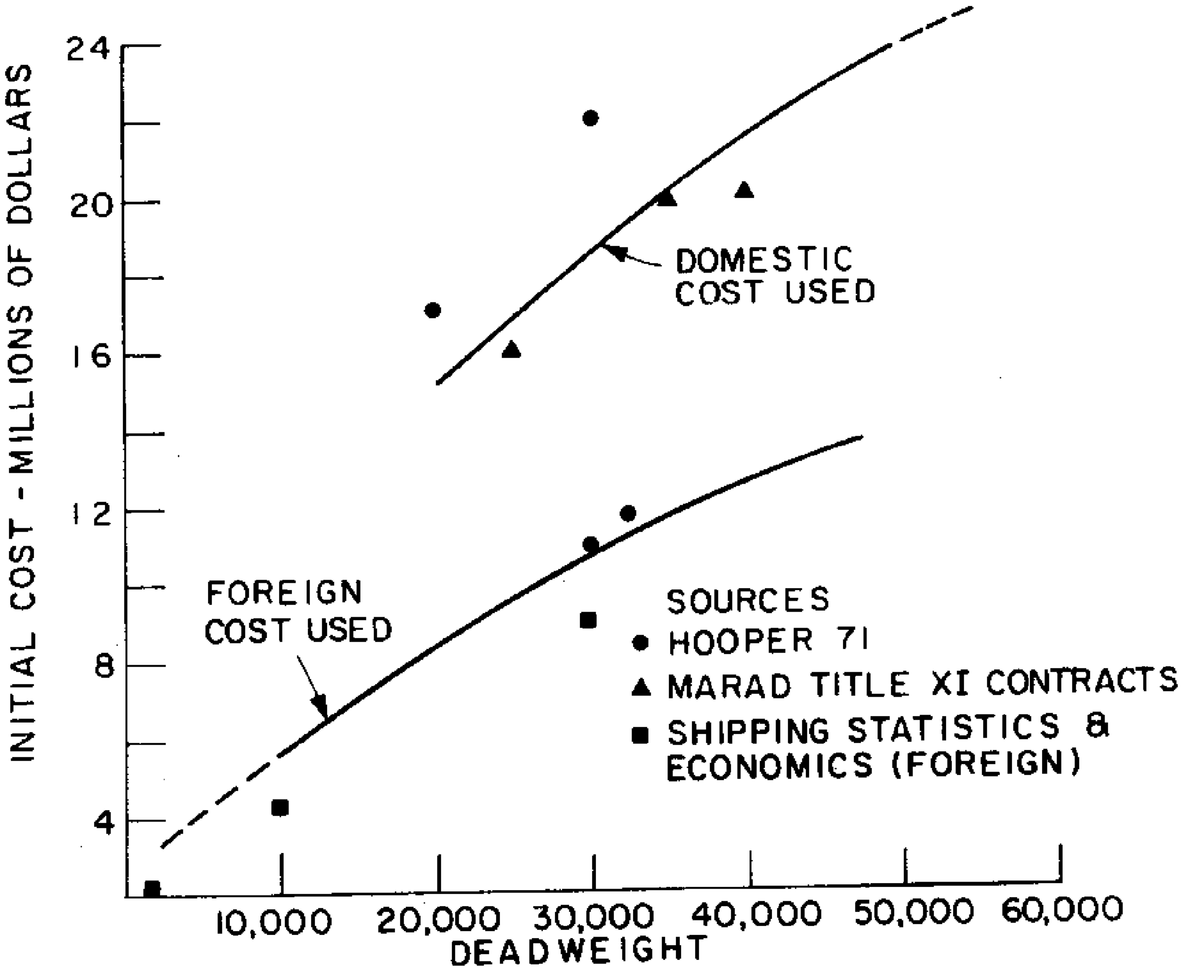

FIGURE I. 2.13 INITIAL COST OF SMALL PRODUCTS TANKERS

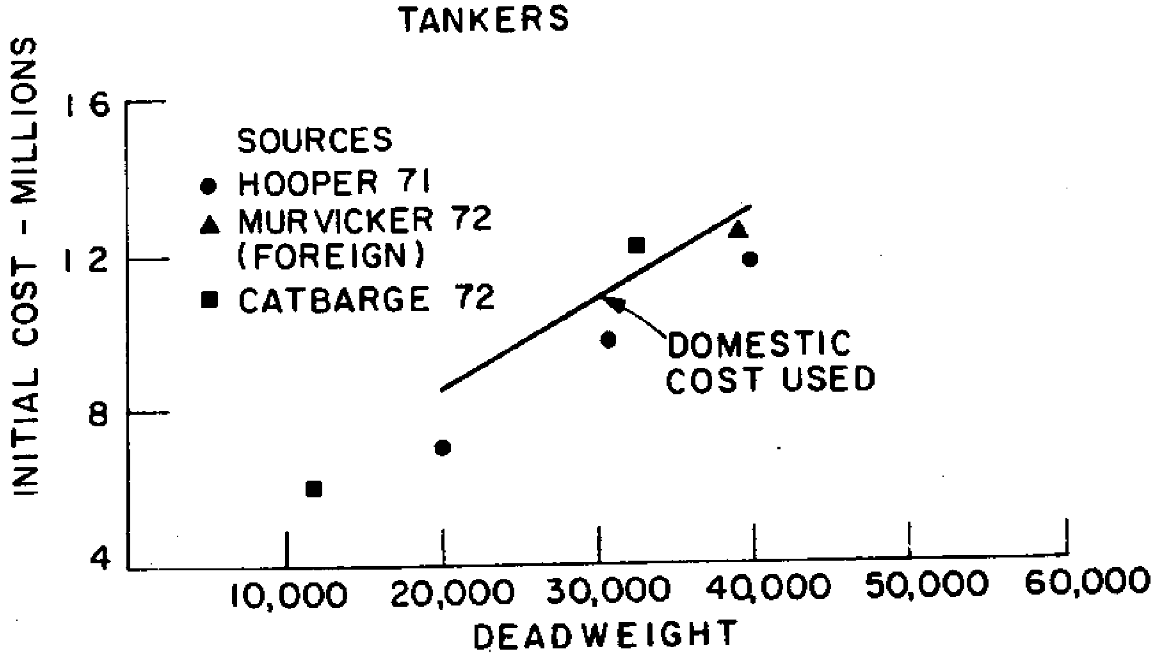

FIGURE I. 2.14 INITIAL COST OF PRODUCTS TUG/BARGES

Tanker manning costs are set at \$750,000 per year based on 32-man, American crew; tug-barge manning at \$450,000 per year based on a 14-man crew (Ericksen 1972, Frankel 1972). Insurance and maintenance are based on 2% and 3% of initial investment per year. Tanker life is set at 20 years and tug-barge life at 15. The tankers are slow speed diesels whose fuel consumption is given in Figure I.2.4. Tanker fuel is priced at \$20/ton. The tugs are medium speed diesels burning diesel oil priced at \$28/ton. All products carriers less than 50,000 tons have a 10 hour unloading time. Discharging rates for larger products carriers are the same as those in Figure I.2.5. Tankers of less than 40,000 tons are assumed to be handled at alongshore terminals by three 3,500 hp tugs; larger tankers by four tugs. Barges are assumed to be handled by two tugs. Pilotage charges are based on present Boston and Delaware Bay rates.

I.2.4.3 Assumptions concerning products reception terminals

PRODIST currently considers two options with respect to vessel-based products reception terminals:

1) the present system;
2) the present system with the exception that Boston is served by an SBM terminal located 5 miles offshore in 72 feet of water.

Table I.2.11 shows the primary characteristics of each of the products reception terminals.

Table I.2.11
Principle Characteristics of Products Reception Terminals

	Draft Limit	Lost Time
Searsport	35'	.25 days
Portland	45'	.15 "
Portsmouth	35'	.15 "
Boston-present	35'	.25 "
Boston-SBM	65'	.15 "
New Bedford	32'	.25 "
Providence	35'	.45 "
New Haven	34'	.15 "
Bridgeport	30'	.15 "

Our systems costing stops at the unloading flange of the products carrier in the shoreside reception port. Thus, no shoreside products terminal outlays are included in our accounts for the present terminals. The SBM off of Boston is handled in exactly the same manner as the crude reception SBM terminals with the exception that the oil is pumped ashore by vessel pumps, no offshore platform is provided, and the non-SBM cost reduced to five million dollars to handled shoreside distribution to present storage terminals.* Bloch (1971) finds that vessel powered pumping will be feasible for this terminal; however, SBM capacity is reduced to 130 ships per year to account for longer unloading time. Under the unassisted mooring system, Bloch concludes that SBM's will be inoperable to weather no more than 15 days per year. Per-mooring operations are put at $250,000 per year. The resulting terminal is considerably cheaper than the $34,000,000 fixed platform system proposed by Harris to Massport (Harris, 1971). This is due not only to the fixed structure employed in that alternative, and the more strongly weather-limited, more expensive assisted mooring required but also what appears to be a large amount of overcapacity in their pipelines to shore. For the purpose of this report, these differences need not concern us unduly. In the results of Chapter I.8 we will indicate how expensive such a terminal could be before it would no longer be an economic investment for each development hypothesis. However, at a more detailed level, it is mandatory that the analysis of offshore products terminals cover a wide range of possible designs and not focus narrowly on what well may be an unnecessarily expensive Harris design.

Our costing philosophy implies that neither the Boston offshore terminal nor, more importantly, the pipeline distribution system is given credit for any waterfront currently devoted to oil handling which would be released to other uses by these alternatives.

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*See Tables I.2.2 and I.2.3.

I.2.4.2 The pipeline products distribution system

The pipeline products distribution system consists of two trunk lines emanating from Dighton, each consisting of three links. Westward, the line runs to Providence, thence to New Haven and thence to Bridgeport. Northward, the line runs to Boston, then to Portsmouth and then to Portland. Pumping stations are provided at Providence, New Haven, Boston and Portsmouth as well as Dighton. Searsport is assumed to be served from Portland by tanker/barge which the program selects in the same manner as described earlier. New Bedford/Fall River consumption is assumed to be served directly from the refinery site. Each ten years the package examines the throughput increase on each link through ten years in the future and chooses that combination of pipeline diameter and pumping power which handles the increase in the minimum present value cost manner. In short, products pipelines are handled in the same manner as crude reception lines, looping each link every ten years. Pipeline design criteria and costs are those given in Table I.2.3.

I.2.4.5 The secondary redistribution system

All products distribution costs are taken up to the present storage tank batteries. However, neither the cost of products storage nor the cost of the secondary redistribution to minor ports, presently handled primarily by small barges, is included. The basic assumption here is that this secondary reshipment system is essentially independent of the form of the system delivering products to the eight major ports. This assumption is considerably less true for the southeastern Massachusetts refinery than the others, for undoubtedly some of the large minor ports such as Plymouth, New London, etc. would be served by pipelines coming off the main header. However, we have not given the pipeline option any advantages of this alternative secondary distribution system. They could be substantial.

While it is true, with the possible exception of the southeastern New England refinery, that the secondary redistribution system will not be affected by the alternatives we are considering in this study and hence need not be analyzed explicitly, given our concentrations on differences, an overview of this system is of some interest primarily because secondary redistribution by vessel accounts for a portion of the environmental risk which the region is presently taking with respect to oil, the West Falmouth spill being a graphic reminder of this.

Details of oil movements within the New England region are skimpy at best. Data from the Army Corps of Engineers was analyzed for the volume of oil received and shipped at each of 24 ports, major and minor, within the region in 1970, as well as the number of barge and tanker arrivals. These volumes by port are shown in Table I.2.12. Unfortunately, this data was not broken down by destination for outgoing vessels nor port of origin for incoming. The Corps does not classify a vessel as tanker/barge, but rather self-propelled/non-self-propelled. There are many barges in use which have some form of propulsion, leading to some difficulty in interpretation. After discussions with the Corps and several operators, all self-propelled vessels under 18 ft draft were classified as barges. As a check on this assumption, data was obtained from the Massachusetts Port Authority for the port of Boston. Counting self-propelled vessels under 18 ft draft as barges brings the Corps data into reasonable agreement with the records of the Port Authority.

Since there is no data specifying origin and destination simultaneously, there are a number of possible patterns which are, at least conceptually, consistent with the data. However, the one such pattern which appears to be both consistent with the data and at the same time minimizes crosshandling is shown in Figures I.2.15 and I.2.16 for the

	Tankers in (arrivals) - full	Tankers out (clearances) - full	Barge arrivals (full) total	Barge clearances (full) total	Tons crude in - foreign $x10^3$	Tons other in - foreign $x10^3$	Tons other in - domestic $x10^3$	Tons other out $x10^3$	Barge arrivals (> 20 ft) extraregional - full	Barge arrivals (< 20 ft) Intraregional - full	Net product in tons x 10^3	
Searsport	45	-	233	10	-	552	154	6.3	-	233	699.1	2477 barge arrivals (< 20 ft) north of Boston
Beals Harb.			5				.1	-		5	.1	
Portland	715	-?	1,000	300	23,039	1,420	3,888	94	50	950	5,214	
Carvers Harb.			193				5.2			193	5.2	
Rockland Harb.			382				6.2			382	6.0	
Southwest Harb.			19				.017			19	.017	
Stonington Harb.			2				.003			2	.003	
Portsmouth, NH	89		100	17		816.8	995	53.4	10	90	1,758	
Gloucester			391				9			391	9	
Salem	53		55	2		939	305	1.2		55	1,242.8	
Lynn			5				7.6			5	7.6	
Beverly			152				180			152	180	
Boston	657	85	87	2,275	19.8	7,389	12,795	2,002	87	-	16,182	
Plymouth			3				43			3	43	2274 barge arrivals (< 20 ft)
New Bedford	17		160	28		437	49.5	14		160	472.5	
Fall River	179	?	625	110	427.6	1,432	1,887	117	25	600	3,202	
Vineyard			111				35			111	35	
Nantucket			24				27			24	27	
Providence	382	?	1,241	201		2,150	5,898	495	41	1,200	7,553	
Newport	2		136				97			136	97	
Block Island			40				8			40	8	
New London	89	?	209	453		1,555	696	1,420	9	200	831	
New Haven	347	?	650	500		2,989	5,969	1,409	48	602	7,549	
Bridgeport	104		380	60		1,728	1,355	195	1	379	2,888	

TABLE I.2.12 SUMMARY OF CORPS OF ENGINEERS DATA ON 1970 NEW ENGLAND OIL MOVEMENTS

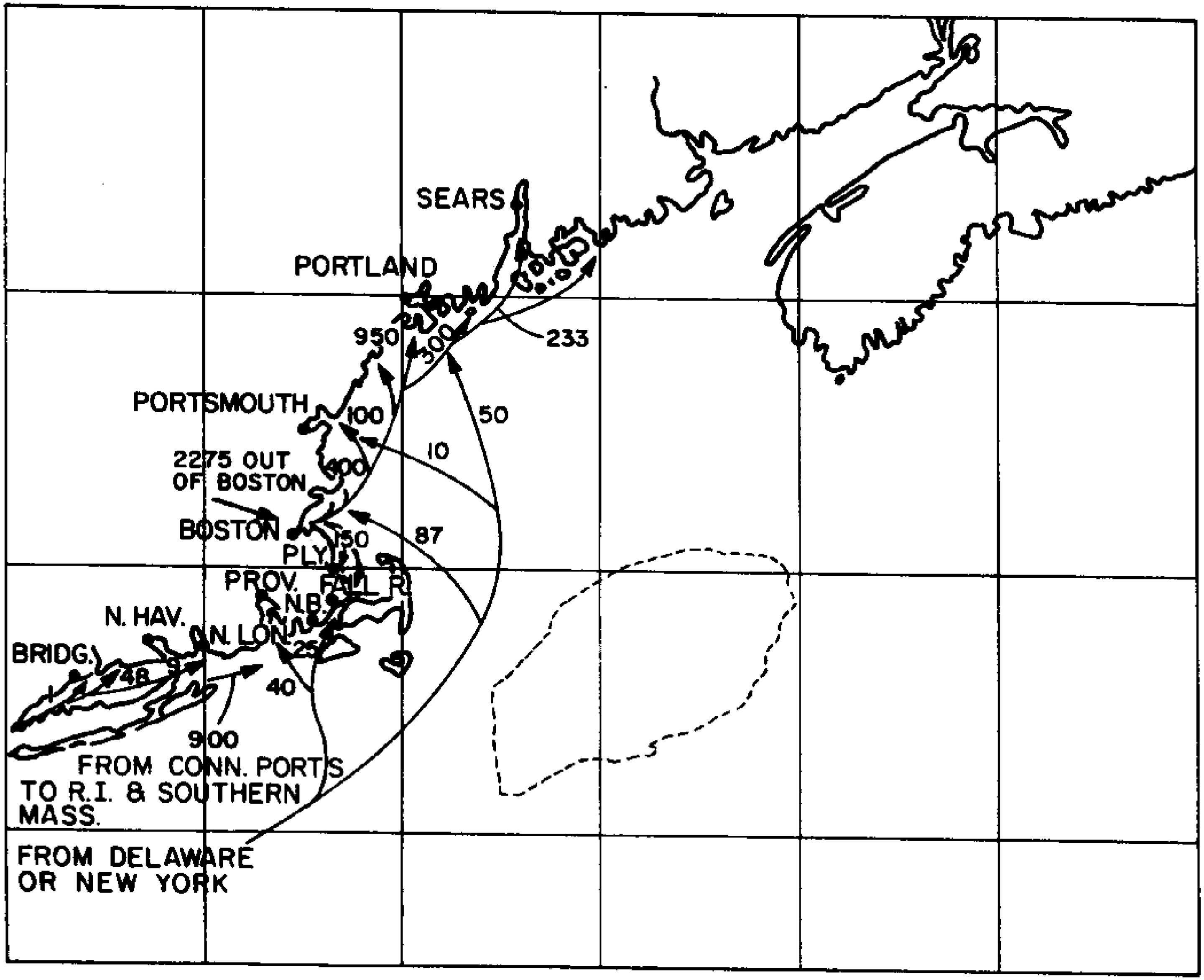


FIGURE I.2.15 BARGE TRAFFIC – NUMBER OF ARRIVALS PER YEAR

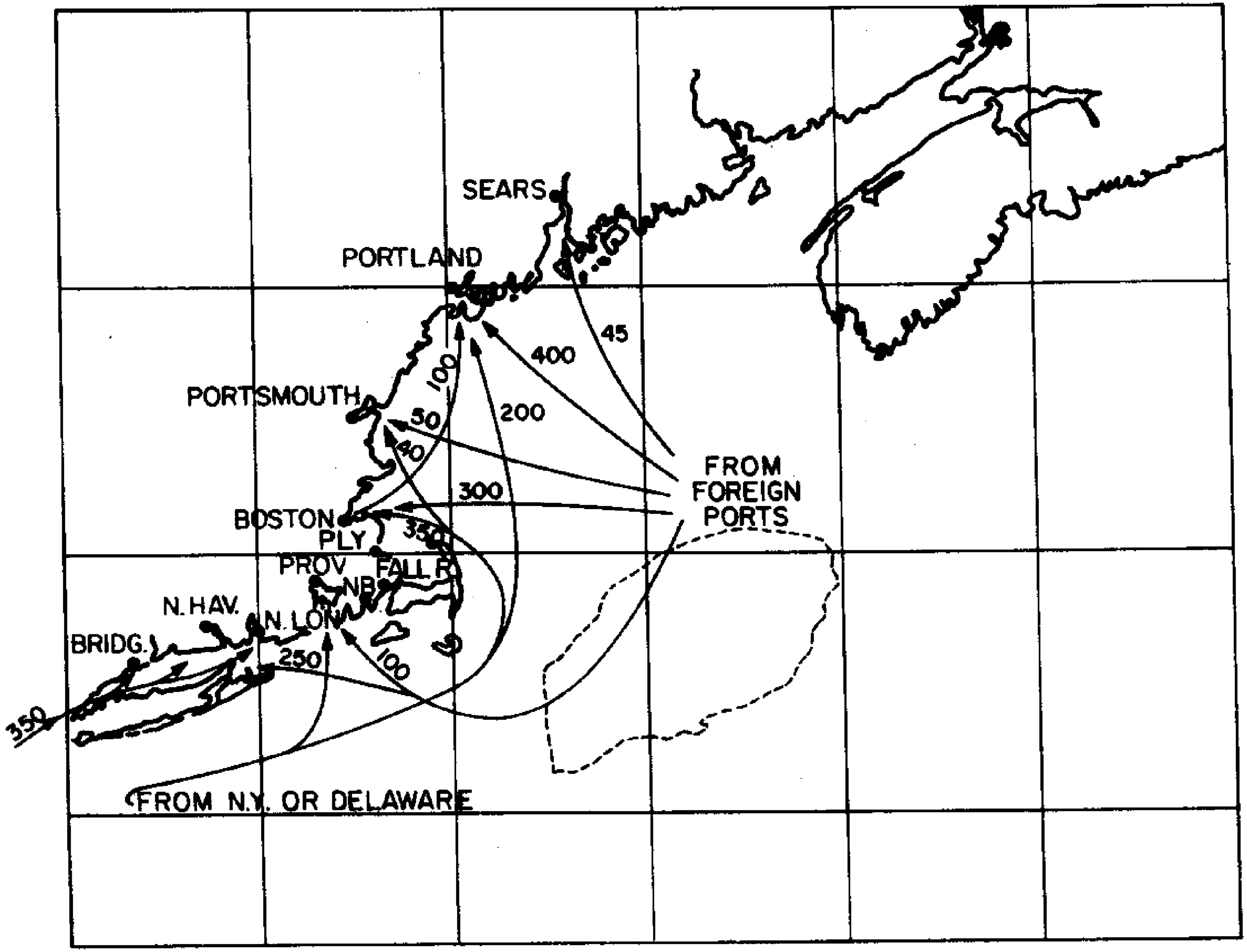


FIGURE I.2.16 TANKER TRAFFIC - ARRIVALS PER YEAR

year 1970. Figure I.2.15 gives barge arrivals and departures, Figure I.2.16 tanker. In developing these networks, it was assumed that barges of greater than 20 ft draft were large extraregional barges, i.e. originating from a port outside of New England (presumably New York or Delaware). If it is assumed that Boston is the main transfer port for redistribution to points from Cape Cod north, then the total of outgoing barges from Boston agrees pretty well with arrivals at these ports. The one discrepancy is in the small ports in Maine which have a large barge traffic but low oil throughput. It is most likely that these ports have very limited storage facilities and so require small portions of a bargeload at short intervals. In the same manner it appears reasonable to assume that distribution to ports south of the Cape is handled mainly be transshipment to barges at Bridgeport, New Haven, New Bedford, and Providence.

Figure I.2.16 shows a possible traffic pattern for tankers. The 400 or so tanker arrivals at Portland from foreign ports are not a part of the regional products picture as they bring in an annual 23 million tons of crude which is transshipped to Canada by pipeline. The tanker traffic pattern is most likely more complex than is shown, but there is no way to tell how much of the traffic is local and how much extraregional, except for the Port of Boston, using the Port Authority records. These records indicate that there were roughly 100 trips in local traffic versus about 320 trips each for foreign and domestic extraregional traffic.

Figures I.2.17 and I.2.18 show domestic and foreign oil traffic by volume. These figures are consistent with the assumptions in Figures I.2.15 and I.2.16, namely that Boston is the main transfer point for oil movement north of Cape Cod, while Bridgeport, New Haven, New Bedford and Providence handle transshipments to small ports south of the Cape.

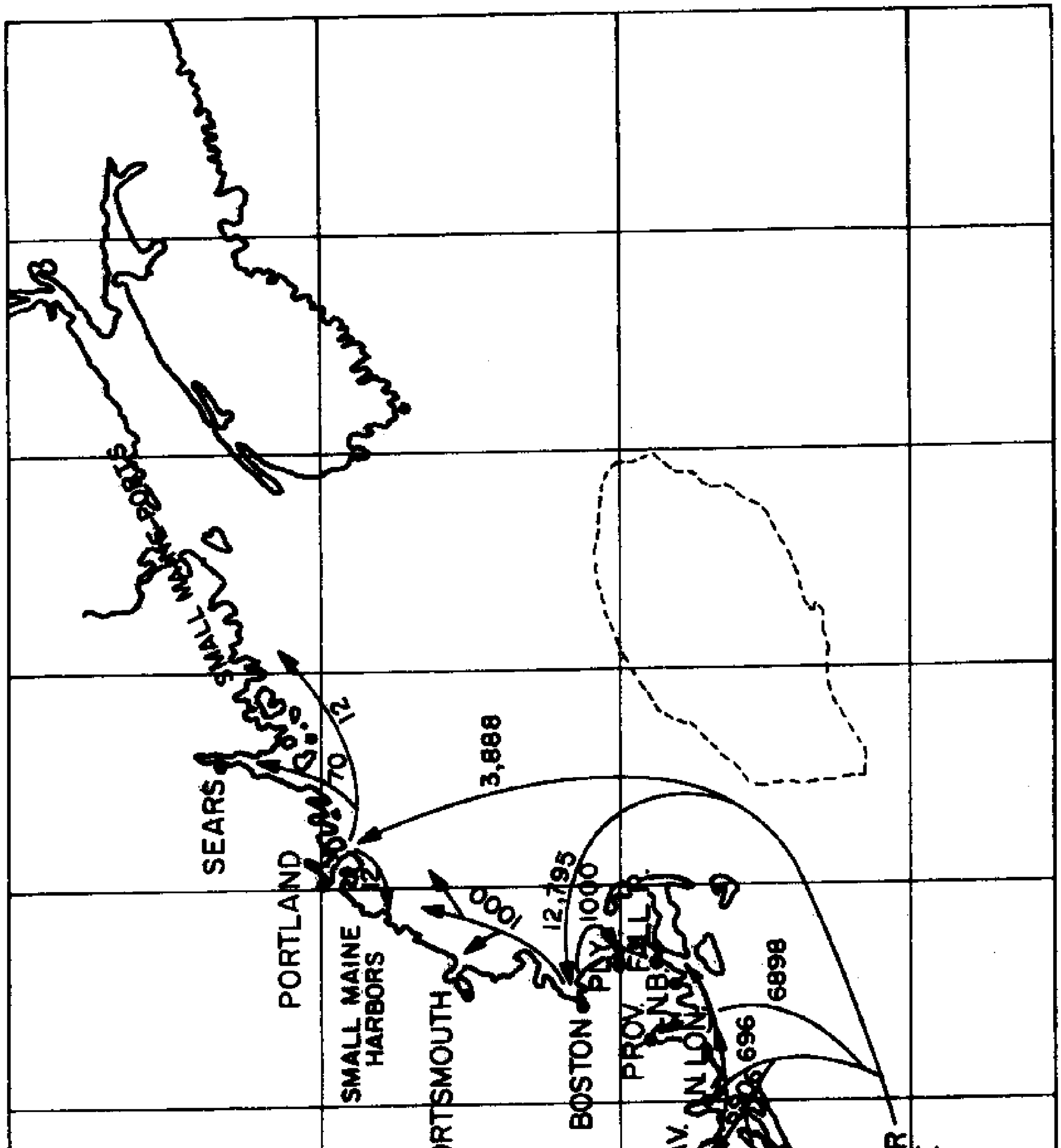


FIGURE I.2.17 DOMESTIC OIL TRAFFIC - TONS $\times 10^3$

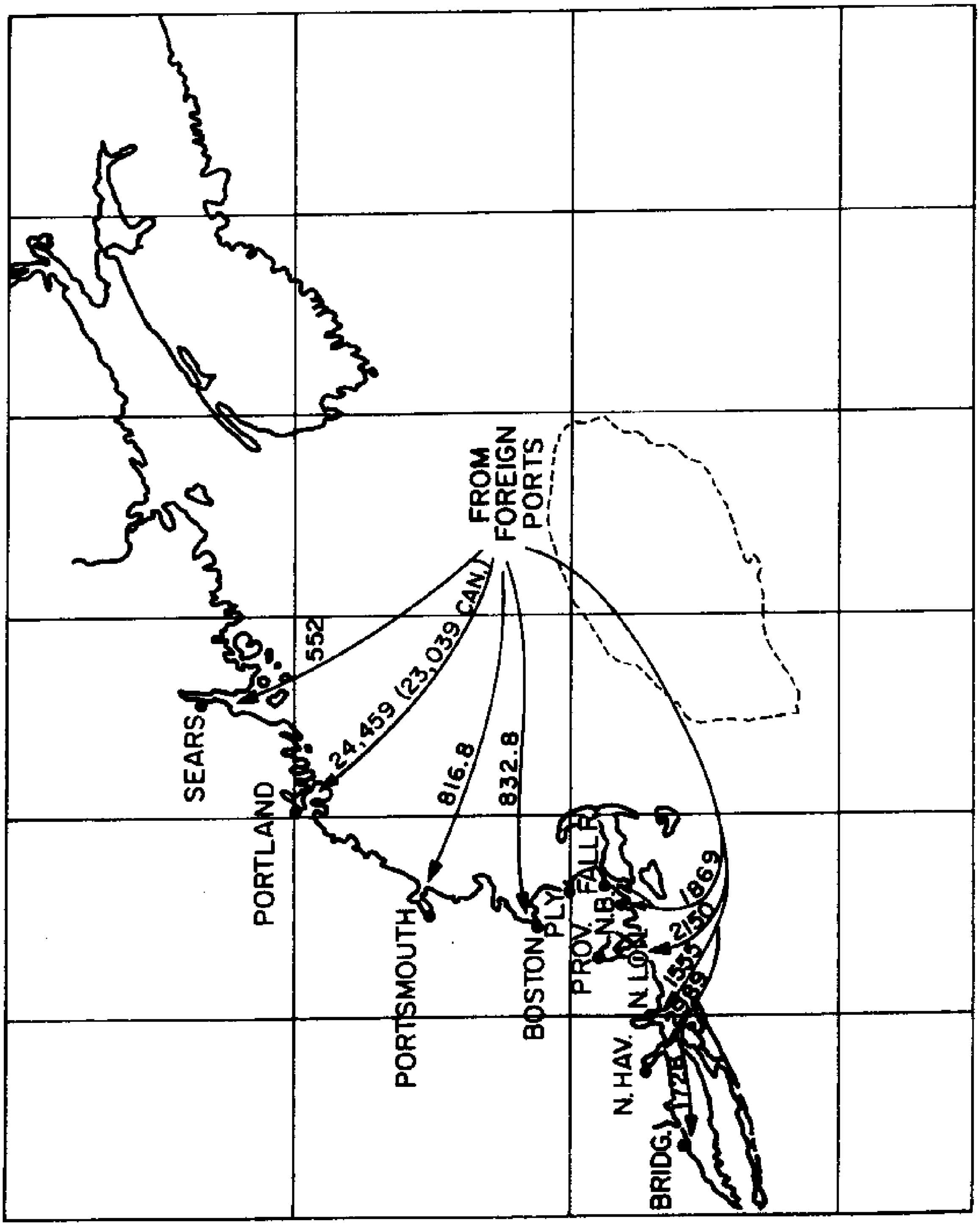


FIGURE I.2.18 FOREIGN OIL TRAFFIC-TONS x 10^3

The surprising thing about this pattern is the amount of reshipment from Boston northward to other major ports which have the same or greater depth capability than Boston, specifically Portsmouth and Portland. In the products distribution systems which the computer designs, no such transshipment takes place. The reason for this transshipment is unclear to the study group. It's almost certainly inefficient economically, requiring extra storage in Boston, an expensive place to put storage. It certainly increases environmental risks, generating two extra handling operations, in and out, within the region and specifically within Boston Harbor, a particularly sensitive area. The most likely cause is that while total volumes to ports such as Portsmouth and Portland are sufficient to support their own products distribution system, the volume shipped to these ports by an individual oil company may not be. In this case, some rationalization may be indicated, and in fact may be taking place. Over the period 1958 to 1967, shipments through Boston grew at 1.3% per year while regional consumption was growing at about 4% per year, indicating a trend away from Boston as a transshipment center.

Assuming such rationalization occurs, the volumes handled by the 15 minor ports in 1970 is 2,800,000 tons or about 5% of the total amount of oil entering the region excluding Canadian crude. Since this oil is both loaded and unloaded within the region on a strictly volume handled basis, this secondary redistribution system represents about 10% of the environmental problems associated with oil. Actually, the situation is somewhat more serious due to the large number of transfer operations and the fact that all spills emanating from this system will occur close to shore. This is discussed in more detail in Volume II.

I.2.4.6 Some Results of PRODIST Computations

Per barrel products distribution system costs for the nine refinery-products distribution system combinations studied are given in Table I.2.13. These are pre-tax investors costs. For the present vessel based system, PRODIST invariably chooses barges. For the larger ports, these barges are sized to the maximum draft limitation: 40,000 tons for Portland, 30,000 tons for Boston, Providence and New Haven. For the other ports, PRODIST chooses either 20,000 or 30,000 ton barges depending on how close the refinery is to the port. For the Boston offshore terminal, PRODIST picks a 40,000 ton barge if the refinery is present Delaware and a 230,000 ton tanker if the refinery has deepwater capability.

As can be seen from Table I.2.13, the off-Boston SBM barely pays for itself on the basis of distillates distribution. However, this does not give the terminal credit for the imported resid it handles under the NO RESID option. This, as we shall see, is quite significant from the terminal's point of view for this resid travels much greater distances than the distillate and thus is able to take much greater advantage of the additional vessel size allowed.

As part of the research, a brief study was made of a fourth products distribution system which involved a 65' SBM off of Portland. Interestingly enough, the program never chose to use this terminal, going directly to shoreside in 40,000 ton barges. It should be remembered the program has no comprehension of the Canadian crude transshipped through Portland which very likely would make use of such a terminal.

The most striking feature of Table I.2.13 is the superiority of the pipeline distribution system. This is at least partially due to the fact that the southeastern New England refinery is located considerably closer to the market than the other refineries. We believe our pipeline costing is conservative. In general, it is based on the highest pipeline cost numbers reported by the industry for non-urban lines. The program does not give the pipeline credit for any savings which it engenders in secondary redistribution. We have not investigated this issue but these savings may be substantial. Some tank truck hauls will be shortened and tank truck traffic in congested areas may be reduced.

Table I.2.13

Unit Products Distribution Costs

Consumption Growth Rate	2%		4%	
Cost of Capital	8%	15%	8%	15%
Present Prod. Dist. Sys.				
Present Delaware	.21	.25	.20	.24
65' Delaware	.18	.22	.17	.21
Pt. Tupper	.23	.27	.22	.26
Machiasport	.16	.18	.14	.17
SBM off Boston				
Present Delaware	.20	.24	.19	.23
65' Delaware	.18	.22	.16	.20
Pt. Tupper	.22	.27	.20	.25
Machiasport	.15	.18	.14	.17
Pipeline Prod. Dist.				
Dighton	.04	.05	.03	.04

I.2.5 <u>The offshore package</u>

I.2.5.1 Introduction

The offshore package (OFFSHOR) determines the national costs, regional payrolls, and investor costs associated with the development of a hypothetical petroleum province offshore New England. In addition, some of the results of the package are used in estimating the environmental consequences of the hypothetical development as discussed in Chapters I.6, I.7, and II.1 through II.5.

OFFSHOR is used to determine that combination of production schedule and transportation system which the private investor would elect to employ in the development of a hypothetical petroleum province centered on Georges Bank subject to a set of user-specified constraints for which typical values are shown in Table I.2.14. These constraints are:

1) the aggregate oil and gas in-place within the province;
2) the number, average depth, average thickness, and spatial separation of distinct reservoirs within the province;
3) the porosity, connate water content, absolute permeability, relative permeability, and compressibility of the potential reservoir rocks;
4) the pressure and temperature within the hypothetical reservoir(s);
5) the effects of temperature, pressure, and composition on the density, compressibility, and viscosity of the potential reservoir fluids;
6) the water depth, significant design wave height, and weather down time limitations at the offshore location;

Table I.2.14

OFFSHOR Input Variables-Typical Values

Oil in place	50 million to 10 billion barrels
Gas in place	80 billion to 10 trillion cubic feet
No of fields	1 to 10
Max Platform/fld	1 to 10
Oil allowable	500 to 10000 bpd per well
Gas allowable	15 million cubic feet per day
Connate Water	30%
Permeability	100 millidarcies
Porosity	20%
Oil gravity	30 API
Condensate gravity	45 API
Gas Gravity	0.6 Sp.G. (air=1)
Formation thick.	75 feet
Vertical Depth	10,000 feet
Max. Deviation	45°
Temperature	200°F
Pressure	5000 psi
Form. Compress.	$3.8 \times 10^{-6} psi^{-1}$
Water Compress.	$3.2 \times 10^{-6} psi^{-1}$
Oil Compress.	$10.0 \times 10^{-6} psi^{-1}$
Reinjection	0%
Water Depth	210 feet
Oil Viscosity	4 cp
Field separation	10 miles
Refinery location	Present Delaware
Terminal Downtime	10%
Royalty	45¢/bbl & 12.5%/Mcf
Lease Fraction	75%
Pipeline Range	6" to 42"
Tanker Range	20,000 to 230,000 dwt.

7) the distances from the offshore location to the potential onshore receiving terminals for both tanker and pipeline transportation systems;

8) limitations on tanker draft at the receiving terminals;

9) limitations on pipeline diameter and throughput as implied by yield stress criteria;

10) the acquisition and operating costs together with the leadtime requirements for onshore exploration, drilling, production, and transport related to the development of the province;

11) the prevailing market prices for delivered crude oil and natural gas;

12) any regulatory restrictions on per-well production, transport, royalties, and lease payments.

The package generates the resulting oil and gas production through time as constrained by the producibility of the formation, development decisions made by the investor, and possible regulatory constraints. The associated platform, drilling, pipeline, and tanker activity are displayed through time together with the revenues (private and public) and the outlays for equipment operation and acquisition.

A basic assumption used in the model is that investor has a perfect knowledge of the petroleum province after the final stage of exploratory drilling. Therefore, given this perfect knowledge and treating <u>all</u> previous expenditures as sunk costs, the only variables under the control of the investor are:

1) the number of drilling platforms to be employed;

2) the rate at which these platforms, i.e. wells will be deployed;

3) the mode of production transport to be employed;

4) the size (diameter, tonnage) of the particular transport mode to be employed;

5) the <u>net</u> production to be offered for sale;

6) when this production will be offered for sale.

The model iterates over these decision variables as they will determine that combination of production schedule and transportation system which the after-tax profit-maximizing investor will elect to employ in the development of the hypothetical petroleum province offshore New England.

I.2.5.1 The reservoir model

The first five variable sets are used to define the geological physical characteristics of the petroleum reservoir(s) under investigation. The descriptions used in this section are intended to illustrate the assumptions which are implicit in the analysis. We do not attempt to determine the relative likelihood of one set of variables with respect to another.

The model assumes that the aggregate oil and gas in-place is distributed among a specified number of identical, homogeneous reservoirs. The temperature and pressure specifying reservoir conditions are used with established correlations such as those of Standing (1952) to determine the volume of hydrocarbons within the reservoir. This, together with the porosity (void space in a unit volume of reservoir rock) and the connate water content (fraction of the void space occupied by immobile waters) are used to find the volume of the reservoir. Finally, by accepting an average net feet of productive pay (thickness), we are lead to the idealization of a specified number of identical homogeneous reservoirs of known spatial distribution.

In addition to specifying the static condition of the reservoir, we must hypothesize how the reservoir will respond when placed into production. This dynamic response of the reservoir is largely dependent on the physical processes which drive the petroleum through the formation to the wellbore. Limiting our discussion to those processes which are naturally occurring, the two extremes in terms of efficiency are internal gas drive and water drive. In the case of internal gas drive, the reservoir may be treated as a closed volumetric system where the reservoir energy is due to the liberation of petroleum gases from solution in the petroleum liquids and the subsequent expansion of these gases. Nearly every reservoir is capable of internal gas drive as the process depends only on the presence of dissolved gases in the crude. Since the gases are more mobile in the formation than the liquids, the gases flow more readily to the wellbore. This results in a rapid decrease in formation pressure (as the reservoir is a closed system no new mass enters the system to replace the production withdrawals) and the depletion of the source of primary reservoir energy. Withdrawals are characterized by increasing quantities of gas production with decreasing quantities of oil production. The ultimate recovery of oil ranges from 5% to 25% of the oil in-place. The ultimate recovery of gas can range from 10% to 78% of the gas in-place. In the case of those reservoirs under water drive, the reservoir must be treated as an open system where production withdrawals are balanced by the influx of water. Since the production withdrawals are balanced, reservoir pressure is relatively constant. Production is characterized by increasing quantities of water relative to oil. However, as water is significantly less mobile than gas, the water drive displaces oil much more efficiently than internal gas drive. Ultimate recovery from a reservoir under water drive can range from 30% to 70% of the oil in-place. As might be expected, water drive recoveries are sensitive to the rate of production. If the reservoir is produced rapidly, it is possible that the water influx will not balance production withdrawals. In this case, the water drive is by-passed and the reservoir is effectively produced as though it were under internal gas drive. Unlike internal gas drive, water drive is not always available. The drive and its efficiency are strongly dependent on the actual geometry of the reservoir (can water influx on one side? two sides?). Rather than hypothesize different reservoir geometries, we have restricted our analysis to that one source of reservoir energy which is nearly always available--internal gas expansion. In making this assumption, we will necessarily underestimate the profitability of any reservoir capable of water drive recovery (rigorously, some water drives can yield lower profits to the investor if either regulatory bodies restrict production and do not allow the drive to be by-passed or gas fields which have high recoveries even under depletion drive and whose costs are increased by water disposal).

We have employed the Muskat-Hoss variation of the Schlicthuis mass balance equation to determine the response of the hypothetical petroleum reservoirs under internal gas drive. This model provides for the re-injection of produced gas and for the presence of a gas cap. This allows the solution for the incremental production associated with an incremental decrease in reservoir pressure. Numerous studies have shown that the ultimate recovery of petroleum liquids from a reservoir under internal gas drive is relatively insensitive to individual well rates, field withdrawal rates, well spacing, and pressure drawdown. Therefore, the investor is free to choose the number of wells to be drilled and the rate at which these wells will be drilled without affecting the ultimate recovery of petroleum liquids. In other words, the ultimate amount of oil produced and the dynamic response of the reservoir are a function only of the pressure drop which the reservoir experiences. We have assumed that the reservoir rock is a well-compacted sandstone of uniform horizontal permeability and of low vertical permeability. The most sensitive variable in determining the recovery from the reservoir relates to the relative permeability of the reservoir rocks with respect to oil and gas. If the reservoir rocks are relatively impermeable to gas, the source of reservoir energy will not be rapidly depleted and recovery will be higher. If the reservoir rocks are relatively permeable to gas, increasing gas production will result in a substantially lower recovery. For the model used in this analysis, recoveries range from 9.2% to 22.3% of the oil in-place. Gas recoveries range from 2% to 78%. In both the cases of lower recovery, the pressure in the formation is always above the bubble point (that pressure at which free gas first evolves from solution) due to the low gas/ oil ratios (50/1). Production is due to formation compression and water expansion. In the cases of the higher recoveries production takes place both above and below the bubble point. If the gas and oil in-place are initially below the bubble point, a gas cap is assumed to be present. If production begins above the bubble point, a gas cap is assumed not to form (should a gas cap form, recoveries can be somewhat higher than those predicted). The reader is referred to a paper by Arps and Roberts (1956) for a discussion of the mehtod used in this analysis. In this model, a number of wells are drilled each year, this number specified by the decisionmaker. The individual well rates are calculated assuming pure radial flow in a bounded drainage area with a flowing wellhead pressure of 500 psia. We have neglected frictional and turbulence losses between the sandface and the wellhead. The area of drainage has been calculated based on an even well spacing. Therefore, given the physical characteristics of the reservoir and the number of wells to be drilled as a function of time, the gas and oil production through time may be determined in a consistent manner. In those cases where well rates are legally constrained to some allowable rate, production per well is cut back to the allowable.

The reservoir model is based on purely physical assumptions which are implicit in the construction of the model used for this analysis. Recapitulating the major assumptions used in this analysis:

1) all fields are capable of compression drive above the bubble point and of internal gas drive below the bubble point;
2) relative permeabilities are based on a well-compacted sandstone;
3) all reservoirs are assumed to be homogeneous with uniform horizontal permeability and low vertical permeability;
4) all losses between the sandface and the wellhead are neglected;
5) gas re-injection is not considered.

I.2.5.3 The field development model

For convenience, field development is classified into three stages - exploration, development drilling, and production. In the case of exploration, we have assumed that the first stages of seismic survey and exploratory drilling take place three years before development drilling. A minimum of nine exploratory wells are drilled at a cost of $1,500,000 per well. Additional exploratory tests are assumed to increase with the square root of the number of producing structures. A general seismic survey costing $600,000 is based on a 10 mile by 10 mile grid covering Georges Bank. Detailed seismic survey of each producing structure is calculated on a 1 mile by 1 mile grid at a cost of $600 per line mile.

The resulting cost function for exploration dependent on the number of fields (NFLDS) and for formation area (AFORM) is:

$$EXPL = 6.0 \times 10^{5} + 600*\frac{NFLDS*AFORM}{(5280)^{2}} + 4.5 \times 10^{6}(\sqrt{NFLDS} + 3)$$

None of the exploratory wells is assumed to be capable of production, i.e. these wells are not given credit as potential producers. It is assumed that all exploratory seismic and drilling crews are non-New Englanders.

For development drilling, each structure is equipped with a single permanently manned 12 pile (24 well) production platform. Additional unmanned extension platforms of 12 piles (24 wells) are added depending on the development decisions of the investor. The well spacings are assumed to be limited to a stepout at 1,500 feet subsurface of 2 degrees per hundred feet with a maximum deviation of 45°. Drilling costs are taken to be $18 per deviated foot for depths of less than 10,000 feet subsurface. This includes all charges except for completion, platforms, and non-contractor operations. Of the 24 wells per platform, it is assumed that twenty are successfully completed at a cost of 1.4 times their drill cost. The other four wells are assumed to be abandoned. The resulting cost function as dependent on slantangle (SA), success ratio (DSR), and vertical depth (VD) is:

$$DC = 24*18*(VD+1500\ COS(SA)*(VD-1500))*(1.0+.4DSR)$$

This relation is based on a $6800 per day rig rate and on 600 feet per day with a double-wall drill pipe assembly (Combes, et al., Chevron Oil Co.). This relation assumes that the wells are normally pressured.

For production, each field is equipped as described above. The extension platforms are connected to the production platforms through a gathering net. Each extension platform is assumed to be equipped with a test separator, a gas flow line, a single stage gas-oil separator, an oil flow line, and glycol treatment facilities. It is assumed that the one stage gas-oil separator was of the double barrel horizontal type. Costing and sizing were based on a flow rate of 40,000 bopd at a gas-oil ratio of 1500:1 with a residence time of one minute. The crude was treated with silicone to deter foaming at high flow rates. As the separator was oversized for most applications, no allocation for surging was made. The outlet gas stream was glycol dehydrated and amine sweetened prior to recompression. Based on data published by Maher & Coggins and McMinn, the total cost came to \$132,000 installed. Platform erection was assumed to require thirty days of derrick barge rental at rate of \$32,000 per day. Platform acquistion costs were based on an arbitrary water depth and design wave of 65 feet. Neu (1972) has reported that the design wave for Georges Bank is near 65 feet. Accepting Neu's estimate, the design wave for Georges Bank is intermediate between that of the Gulf of Mexico at 45 feet and that of the North Sea at 85 feet. Using cost data obtained from Marshall (1972) and Daley(1972), a platform jacket structure for Georges Bank would cost \$2,400,000 in 50 feet of water and \$5,500,000 in 400 feet of water exclusive of mobilization and erection. The cost function used in this study which includes erection, production facilities and riser connections is dependent on water depth (WD) and the gathering net cost (GC) which is sized on flow rates and platform separation. This cost function is:

$$DPC = 9285.7\ WD + 3.8\text{x}10^6 + GC$$

The permanently manned production platform is assumed to be equipped with same type of first stage separation equipment. In addition, a second and third stage separator are added. The inlet flow is taken to be 200,000 bopd at a gas-oil ratio 1000:1. The stages go from 275 psia to 75 psia. The evolved gas is dehydrated and sweetened prior to co-mingling with the first stage outlet stream and the production from the extension platforms. The total cost of this system was \$1,265,000. The total gas stream is recompressed prior to discharge at the header. The erection,fabrication, and materials costs for the jacket structure of the production platform was taken to be same as that of the extension platform previously described.

However, provision for crew quarters, generator packages, a heliocopter pad and a flare tripod add an additional \$1,420,000 to the acquisition cost. The resulting cost function dependent on the water depth (WD) and the number of riser connections through the number of platforms per field (MAXP) is:

$$PPC = 4.21x10^6 + 8857.14\ WD + 2(MAXP + 2)(219.3\ WD + 7.5x10^4)$$

The transport platform group consists of one 4-pile quarters platform, one 8-pile separator platform with compressor units, a large flare tripod, and a underwater liquids storage battery. All of the production platforms are connected to the transport platform group through a header system, see Figure I.2.19. Erection time per platform is taken to be 20 days. The resulting cost function dependent on water depth (WD), compressor/pumping horsepower, and storage is:

$$TPC = 14571.5\ WD + 10.82x10^6 + POWER + STORAGE$$

Horsepower requirements are calculated according to production rates and fluid characteristics as described in EXCRUDE. Storage is sized to provide five days capacity at maximum production rates. Storage is assumed to cost \$20 per barrel stored. If a pipeline is used for production transport, only surge storage is provided offshore. In all the cases of extension, production, and transport group platforms, the investor is assumed to pay for the structure two years before first production. In no case can more than five platforms be deployed in any given year. The operating costs are based on a permanent manning of 120 personnel, one large work boat per field and one light heliocopter per field. The wage rate is taken to be \$600 per week exclusive of overheads, the day rate on the work boat is taken to \$800, and the heliocopter is chartered at \$500 per hour at 10 per cent utilization. Sustinence is is included in the wages of the manning levels. This total operating figure amounts to \$4,108,000 per year per field. Insurance and maintenance expenses are taken to be 9% of the total capital cost annually. Of the total construction bill for offshore facilities, 25% of the non-pipelining expenditures are applied to the New England payrolls. All pipeline expenditures are assumed to be received by

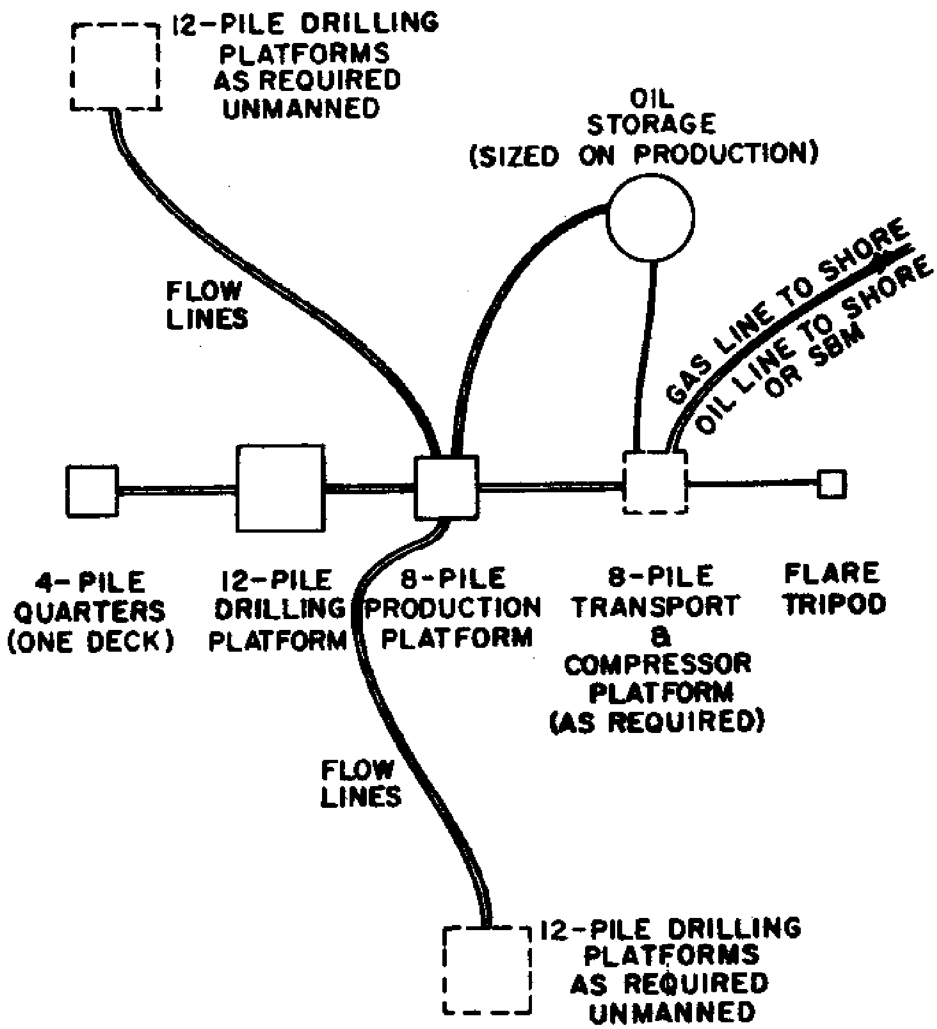


FIGURE I.2.19 TYPICAL RESERVOIR DEVELOPMENT PROGRAM
(NOT TO SCALE)

non-New Englanders. Of the total annual operating bill, 50% is applied to the New England payroll.

Production transportation is carried out by tankers and pipelines in the case of crude and only pipelines in the case of natural gas. All of the construction and operating costs used in EXCRUDE apply in OFFSHOR with the exception that installed horsepower is assumed to cost $175 per horsepower offshore. All tankers used are assumed to be under American registry. Fuel costs for the offshore oil and/or gas lines are caculated by deducting the fuel (natural gas) consumption from the production offered for sale. If the market price for natural gas is sufficently high, the investor tends to use larger diameter pipelines for the same throughputs. The larger lines consume less fuel for the same throughput when compared to smaller lines. The increased revenues from sales offset the higher capital costs associated with the larger diameter pipe. Pipeline right-of-ways offshore are assumed to allow access to the nearest landfall - Cape Cod at 117 miles. Pumping stations are established at this landfall. Pipelines are premitted to serve only a southeastern New England refinery location - Dighton, for example. The natural gas pipeline is costed up until it joins the Algonquin trunk line. Tanker systems are allowed to serve any of the potential refinery locations mentioned in EXCRUDE.

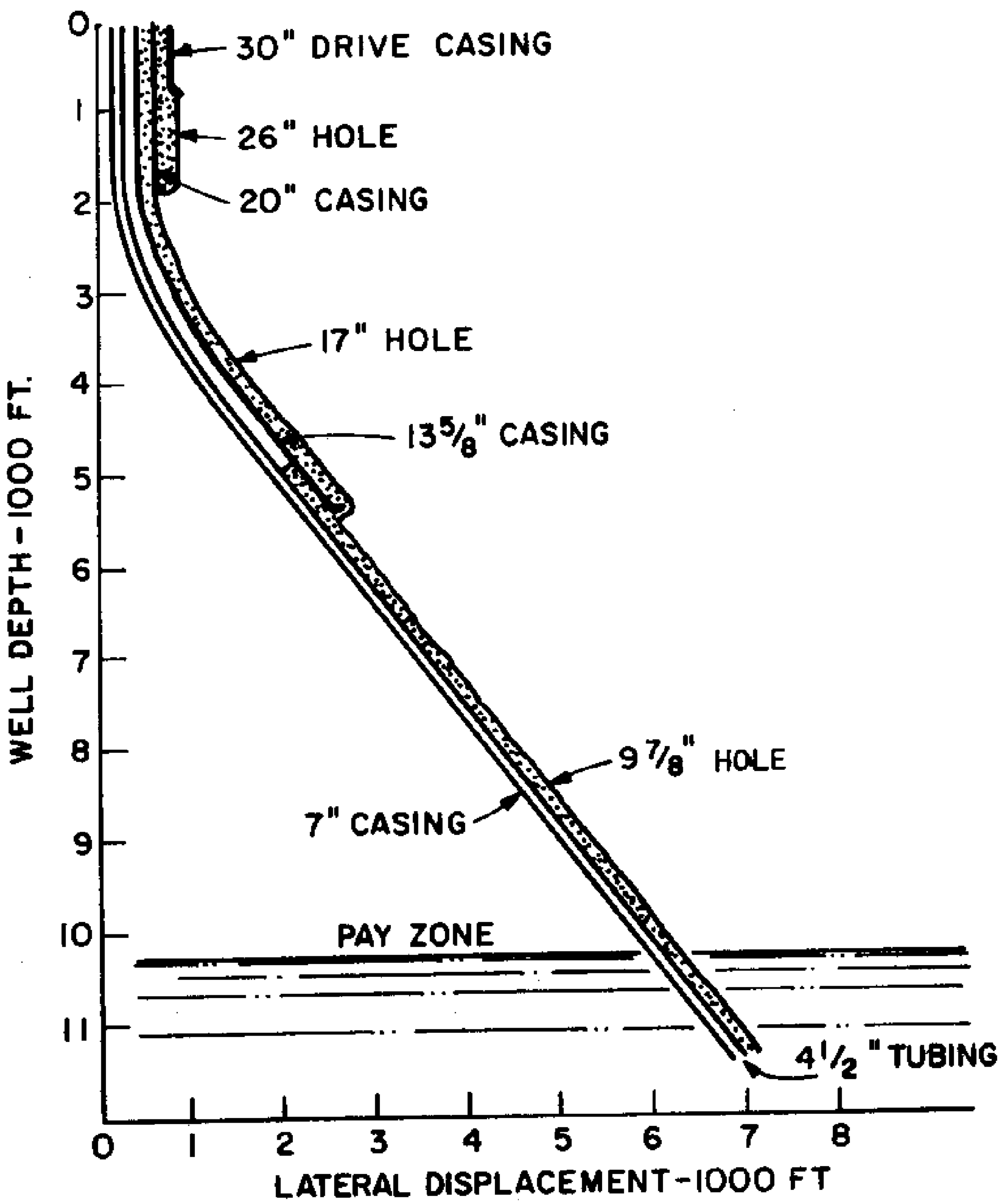


FIGURE I.2.20 TYPICAL WELL

I.2.5.4 Some results of OFFSHOR

The reservoir model and the offshore development model together form the offshore package. This package has been used to calculate the national costs, regional payrolls, and investor costs associated with the development of a hypothetical petroleum province offshore New England on Georges Bank. The provinces studied in this report contain from 50 million to 10 billion barrels of oil in-place with initial gas/oil ratios ranging from 10/1 to 2,000/1. In the case of predominantly gas fields, aggregate gas in-place is varied from 1 trillion to 10 trillion cubic feet with gas/condensate ratios ranging from 5,000/1 to 100,000/1. These aggregate hydrocarbons in-place have been assumed to be distributed between from 1 to 10 distinct producing structures. Each of these structures has been assumed to be 10,000 feet subsurface with a spatial separation of 10 miles. The average thickness of these structures (net productive pay) was taken to be 75 feet. The reservoir conditions were specified to be 5,000 psia, 200°F. The reservoir rocks were taken to be compacted sandstones of 20% porosity, 30% connate water content, and 100 millidarcies absolute permeability. The reservoir fluids were taken as 30° API for crude, 45° API for condensate, and 0.6 Sp.G. for gases. The water depth at the offshore location was set at 210 feet with the nearest pipeline landfall being 167 miles. Lease payments are based on a percentage of the difference in the market value of the landed petroleum and the investor's cost of landing this petroleum. Royalties were specified to be $0.45 per barrel of liquids and 12.5% of the posted price for natural gas. In the case of natural gas, it was assumed that the investor would offer the gas for sale provided that the prevailing market price would allow the recovery of his investment in pipeline and gas conditioning facilities. If the investment could not be recovered, the gas was flared. Restricting our comments to gas-oil ratios of 200:1, 1000:1 and 100,000:1, the associated recoveries for liquids and gases were respectively (23.3%, 59.5%), (14.7%,78.2%), and (89.5%,88%). In general, for the oil fields where gas-oil ratio is less than 2000:1, our recoveries are conservative, reflecting our complete dependence on internal gas drive.

Referring to Figure I.2.21, investor cost per barrel (eq.) prior to lease and royalty payments at an investor's cost of capital of 8% are plotted as a function of the aggregate oil in-place with gas-oil ratios of 200:1 and 1000:1. This curve is based on delivery by tanker or pipeline to our sample southeastern New England location. The per well production rate is constrained to a maximum of 1000 barrels of oil per day. While minimization of unit investor costs does not guarrantee either the minimization of national costs or the maximization of investor profits, the graph does demonstrate the overwhelming importance of aggregate oil in-place in determining national costs. The general pattern is one of extremely sharp economies of scale up to the point where one platform per field is fully utilized and very little in the way of scale economies thereafter. Unit costs range from $5.347 per barrel to $0.704 per barrel depending on the amount of oil in-place. While unit costs decrease by $4.30 per barrel from 100 million to 1 billion barrels in-place, the unit costs drop by only $0.380 per barrel from 1 billion to 10 billion barrels in-place. Adding to this investor payments for royalties amounting to $0.45 per barrel, the minimum size field which the investor will develop lies between 100 and 200 million barrels of oil in-place (this assumes that the investor will not develop oil offshore New England unless the delivered cost of that oil is less than the delivered cost of Louisiana crude - $4.20). Notice that the minimum size field which the investor will develop is limited by the royalty payment.

Of the investor costs exclusive of royalty payments as shown in Figure I.2.21, typical expenditures range from:

Oil In-Place: (14.7% Recovery) (Gas-Oil 1000:1)	200×10^6	10×10^9	
Exploration	\$0.438/bbl	\$0.015/bbl	
Production	1.250/bbl	0.518/bbl	
Transport (oil)	0.363/bbl (T)	0.037/bbl	(P)
Transport (gas)	0.592/bbl	0.134/bbl	
Total	\$2.643/bbl	\$0.704/bbl	

For the fields shown above, the (T) and (P) denote either the tankerage or pipelining of crude oil and condensate ashore. In the case of the smaller field, a single 20,000 dwt. vessel making a maximum of 212 trips per year carries the liquids to shore while a 6 inch gas line is used. In the case of the larger field, a 30 inch crude line comes ashore while two 30 inch gas lines are used. Had the tanker alternative been less costly, three tankers of 80,000 dwt. making a maximum of 462 trips per year would have been necessary for liquids carriage. In the first case, a single 12-pile platform was necessary. In the latter case, twenty-five platforms were used in the development. Refering again to Figure I.2.21, pipelines are more profitable crude carriers than tankers when the field contains more than 2 billion barrels in-place while tankers are favored for the smaller fields. The choice between tankers and pipelines is strongly dependent on the timing of production and on the investor's opportunity cost of capital. When production schedules become peaked, i.e. large inital production rates which rapidly decline, a crude pipeline must be sized to carry initial production and then is only partially loaded thereafter. While the pipeline can not be freely switched to carry additional cargoes, the tankers can be briefly employed and then reemployed elsewhere. Therefore, by using tankers, the investor avoids a less profitable capital outlay. For the larger field, the sheer size of the oil in-place precludes a highly skewed production schedule and the pipeline is the more profitable carrier. While production timing has a purely physical interpretation, the influence of the investor's cost of capital in choosing between tankers and pipelines has an economic interpretation. The investor whose cost of capital is 15% discounts the operating cost advantages of the pipeline and emphasizes the large inital capital commitment of the pipeline. The investor whose cost of capital is 8% values the operating cost advantage of the pipeline such that the pipeline is more profitable for him than the tanker. Finally referring to the potential onshore receiving terminals other than Dighton, tanker shipment costs for offshore oil increase and thereby increase the investor's costs. Tanker shipment to Delaware increases investor costs by $0.06 per barrel, tanker shipment to Pt. Tupper increases investor costs by $0.04 per barrel, and tanker shipment increases investor costs by $0.01 per barrel for Machiasport. For the larger fields, investor costs are increased by additional $0.02 per barrel since Dighton is the only terminal allowed to receive an offshore crude pipeline. All other costs are independent of the receiving terminal location.

It is the practise of certain regulatory bodies to limit per well per bay production to a maximum daily amount known as an allowable. Figure I.2.22 demonstrates the effect of varying allowable on the internal gas drive fields studied in this report.

Figure I.2.21
Unit Investor Costs Before Royalties

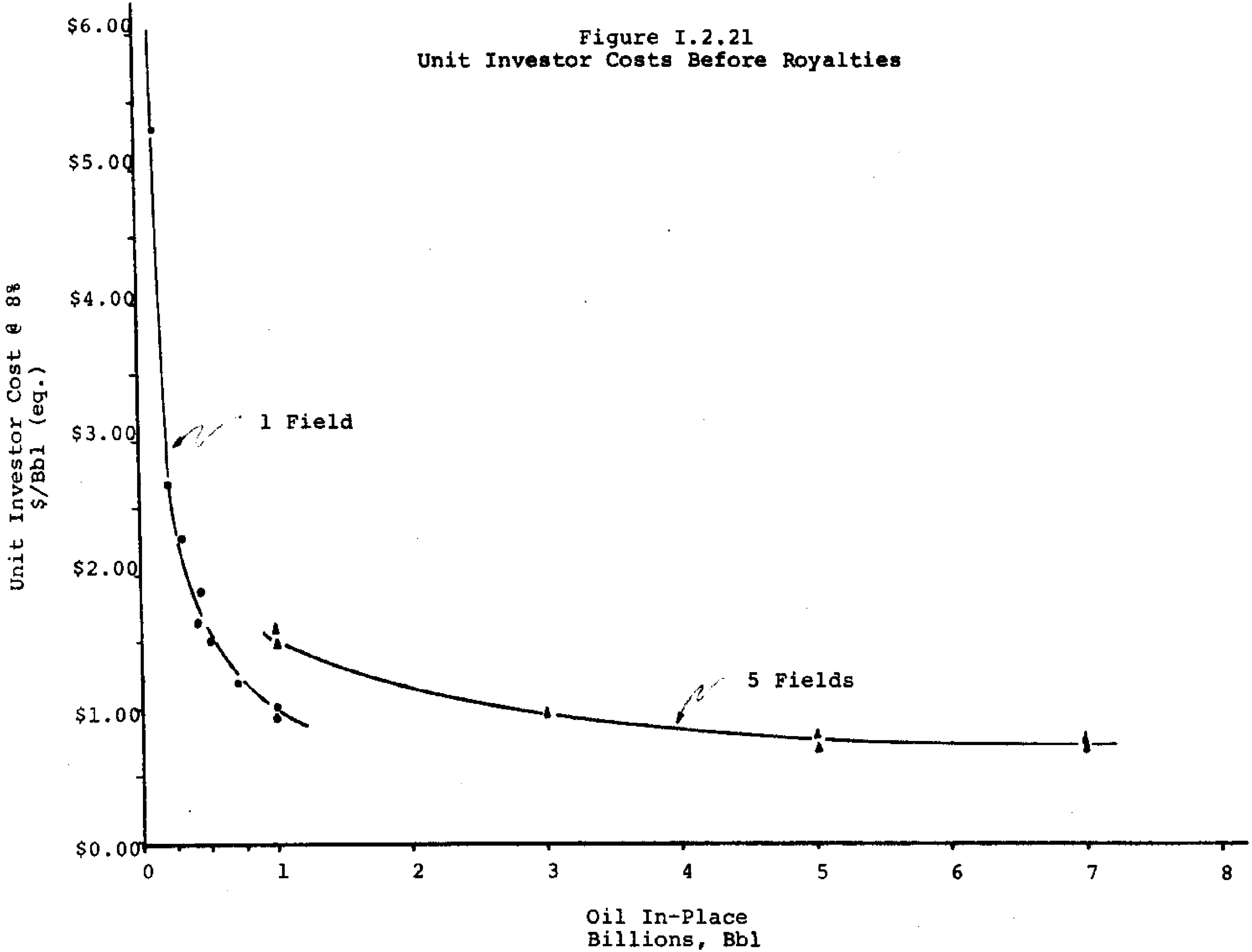
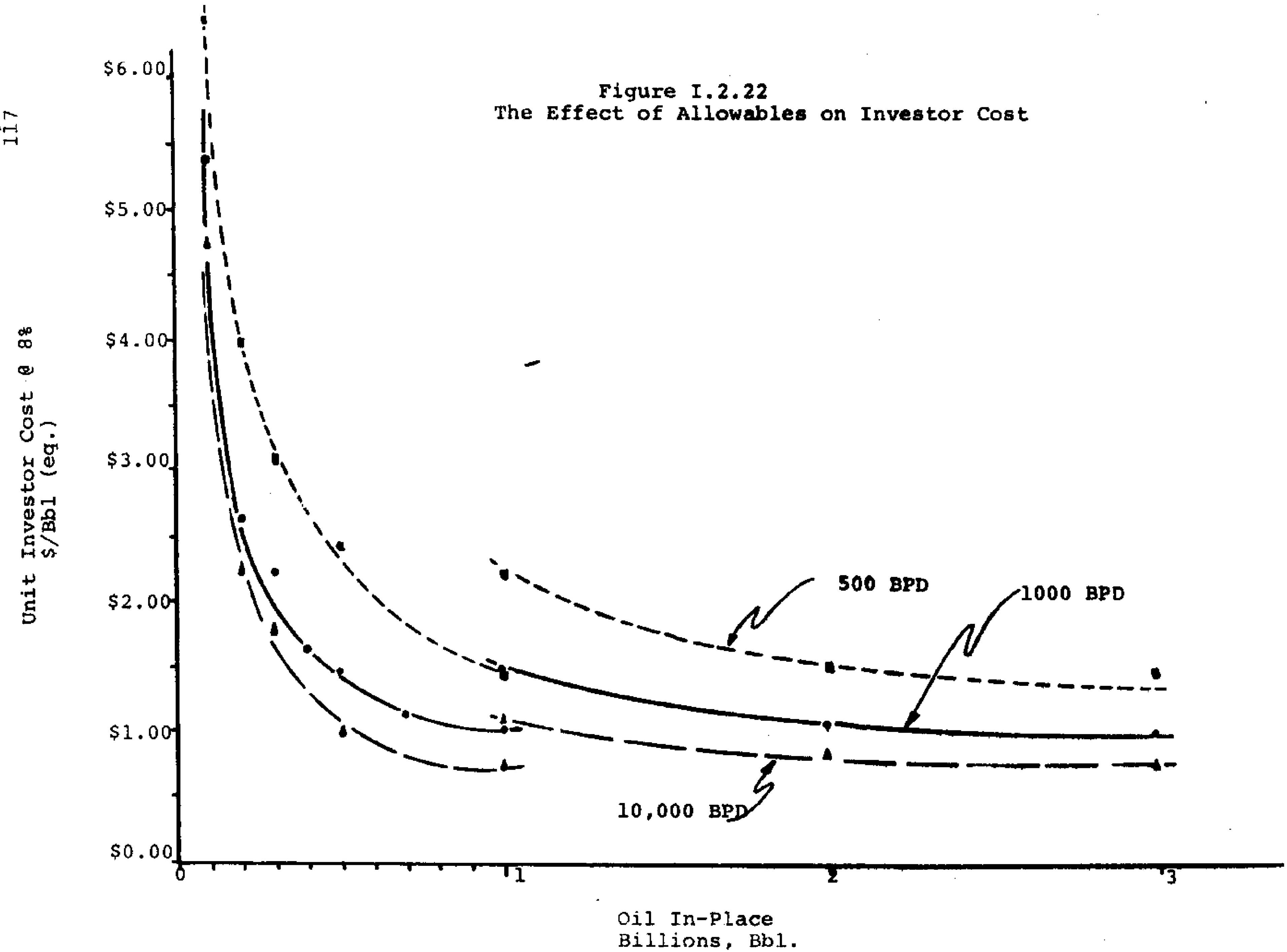


Figure I.2.22
The Effect of Allowables on Investor Cost



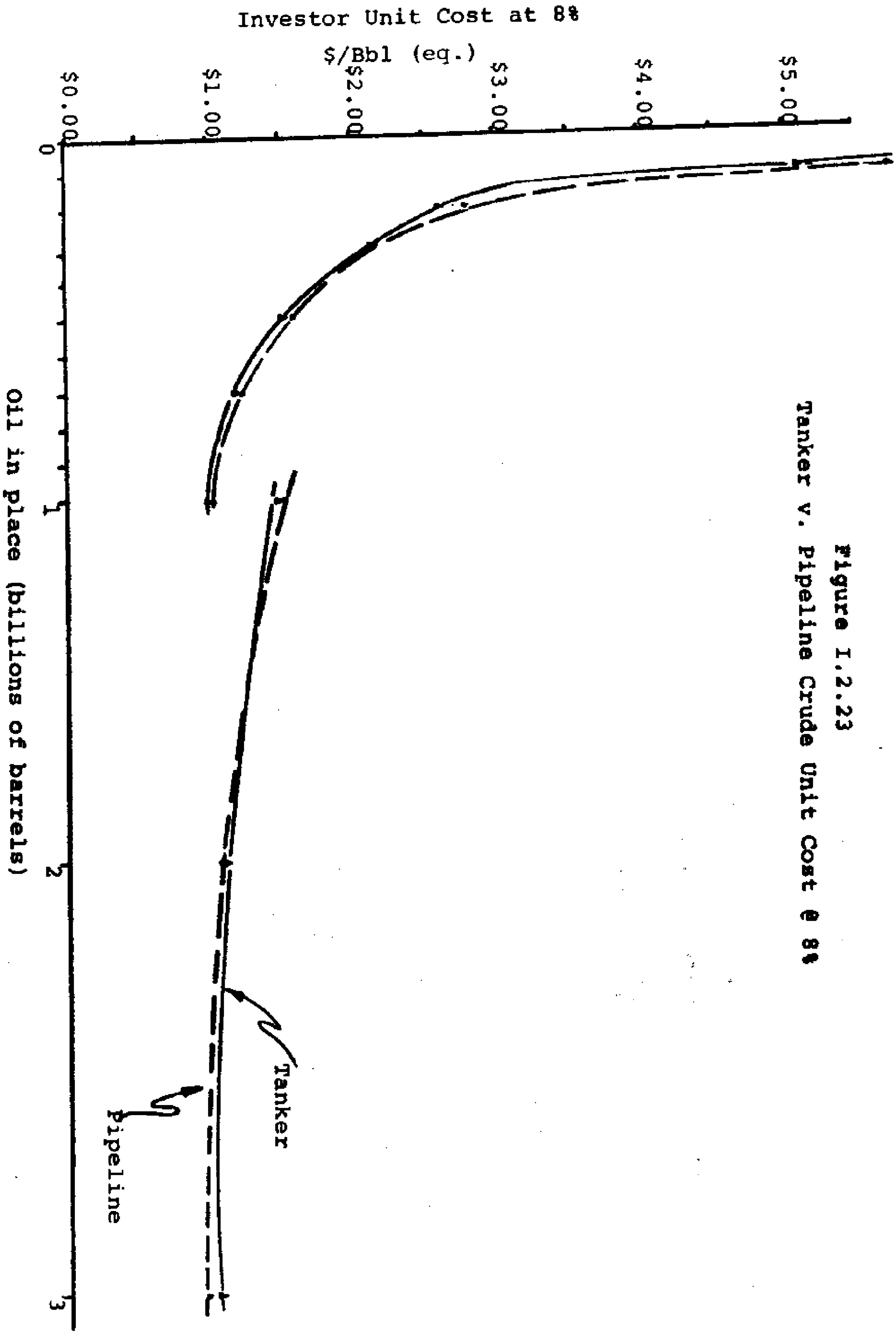


Figure I.2.23
Tanker v. Pipeline Crude Unit Cost @ 8%

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Chapter I.3
The Response of Regional Products Prices to Changes in Cost

I.3.1 The basics of demand and supply

As pointed out in Chapter I.1, environmental considerations aside, there are four ways a change in the New England petroleum system can effect a change in real regional income:

a) through changing the price (or quantities) of petroleum products bought by regional consumers,

b) through changing the real income of regional inputs - employment effects,

c) through changing the real income of regional investors - changing private profits,

d) through changing the revenues and expenses of regional public entities - public profits.

In this chapter, we will address possibility (a). We will develop the principles and assumptions by which we have estimated the change in the cost to the regional consumer of his oil consumption which will result from the various hypotheses. These principles have been made part of the computer simulation which adjusts market prices accordingly and are reflected in the estimates of overall changes in regional real income presented in Chapter I.8.

To investigate petroleum products market price changes, we will make use of two of the most basic concepts in economics: the demand curve and the supply curve. The demand curve indicates how much of a particular product will be consumed for a range of market prices. It reflects the consumer's willingness to pay for the product in question. The demand curve for crude to serve the 1972 New England distilled products market looks something like Figure I.3.1. The NW-SE slope of this curve indicates that if price increases (decreases) less (more) oil will be consumed within the region. The steepness of the curve indicates that over the price range shown, the amount consumed will not change very much with price. If the demand curve were vertical, there would be no change in quantity consumed with a change in price. Several studies have indicated that over the price ranges of interest to us, the demand curve for oil is very steep and, throughout much of this chapter, we will often assume that the curve is vertical over the range of price changes we will be considering, which changes turn out to always be less than $2.50 per barrel or about 6¢ a gallon.

Another assumption we will make frequent use of is that of a competitive market. <u>A competitive market is a market in which neither buyer nor seller can influence the price of the commodity being exchanged</u>. Notice that our definition of competition is quite different from the meaning in general usage. At least some of the petroleum products markets are not completely competitive by this definition. However, with respect to oil, a competitive market is the best thing that can happen from the consumer's point of view. Thus, through this assumption, we shall be able to obtain an upper bound on the direct increase in regional consumer income through price decrease, after which we will examine the degree to which the petroleum products markets diverge from pure competition and comment on the effect of these divergences.*

Assuming we have a competitive market, a valid question is what is the relationship between market price and the amount of a commodity which the oil industry will be

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*Remember in this chapter, we are referring to the markets between the consumer and the oil industry and not the market between the oil industry and the oil exporting countries, which is in no way competitive.

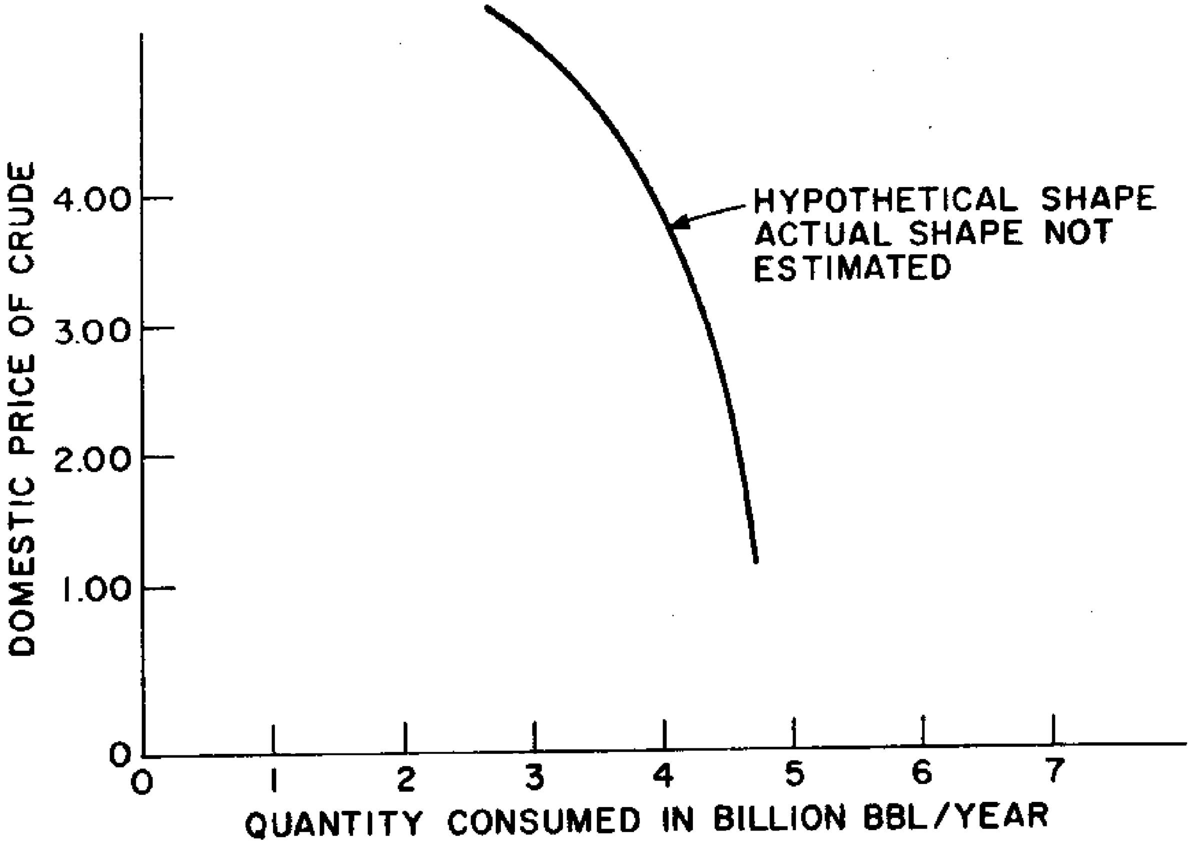

FIGURE I.3.1 HYPOTHETICAL EAST USA CRUDE DEMAND CURVE
DISTRICTS I-IV NON-RESID

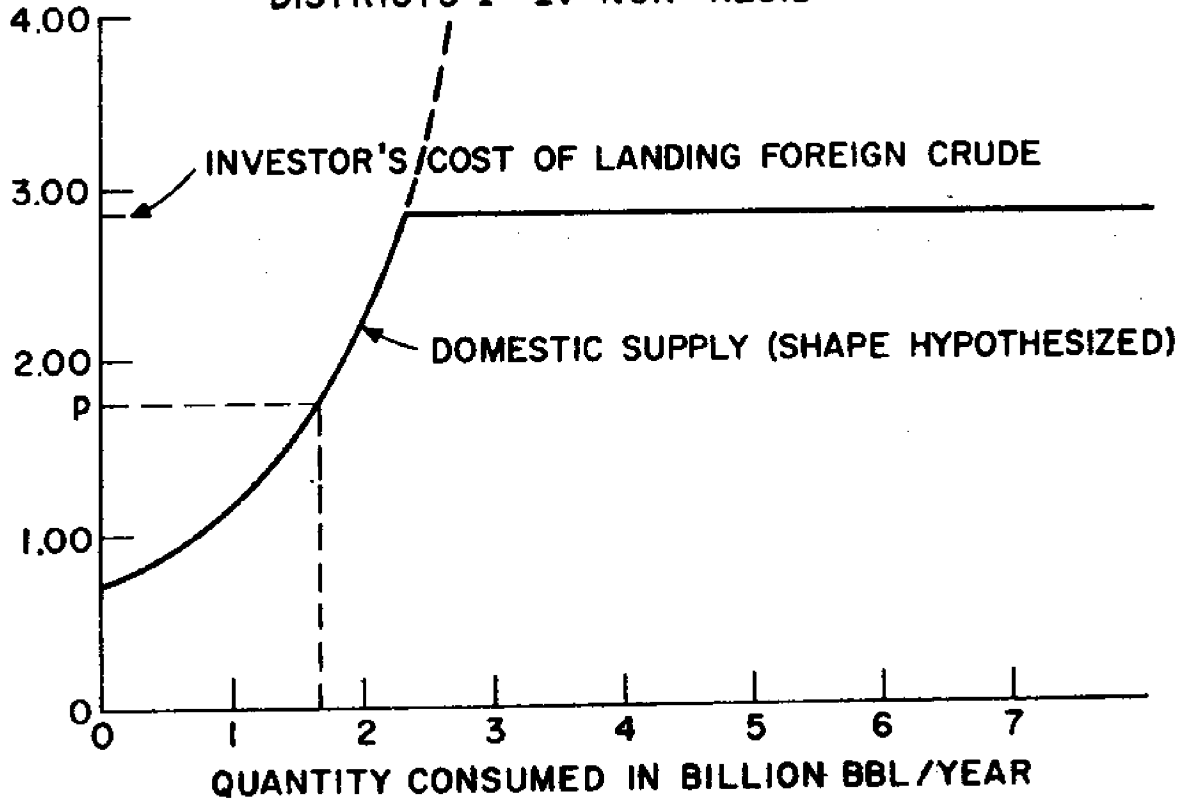

FIGURE I.3.2 APPROXIMATION OF DIST I-IV CRUDE SUPPLY CURVE-
NO QUOTA - NO RESID

willing to supply. The supply curve shows this relationship. Assuming no import quota and average tanker rates, the present supply curve of crude to the eastern half of the U.S. looks something like Figure I.3.2. For landed prices below about \$2.63, only oil from cheap domestic sources would be offered on the market. However, without a quota, as soon as the price rises above the landed cost of foreign crude (about \$2.63), suppliers will be willing to offer an essentially unlimited amount of oil at that price, for they will make money on every barrel sold. The reason why the foreign portion of the supply curve is essentially horizontal is that the exporting countries tend to adjust their prices so that from the U.S. point of view, it's as expensive to import from one source as another.

A little reflection will reveal that the price at any point on the supply curve, say price p and quantity x in Figure I.3.2., indicates the cost to the industry of supplying the xth unit of oil for at any price above p the industry would be willing to supply a greater quantity than x, since it would make money on the additional units, and at any price below p, the industry would not be willing to supply the xth unit, for it would lose money on that unit.

The intersection of the demand and supply curves is the only combination of quantity and price such that the amount exchanged is equal to both the amount consumers are willing to consume at that price and the amount producers are willing to supply at the prevailing price. The market will be in equilibrium: this is the combination of consumption and price toward which a competitive market will move.

Figure I.3.3 shows several hypothetical price changes under competition. In Figure I.3.3a, the shift in demand from DD to D'D' generates an increase in price from p to p'. In I.3.3b, the shift in supply from SS to S*S* decreases

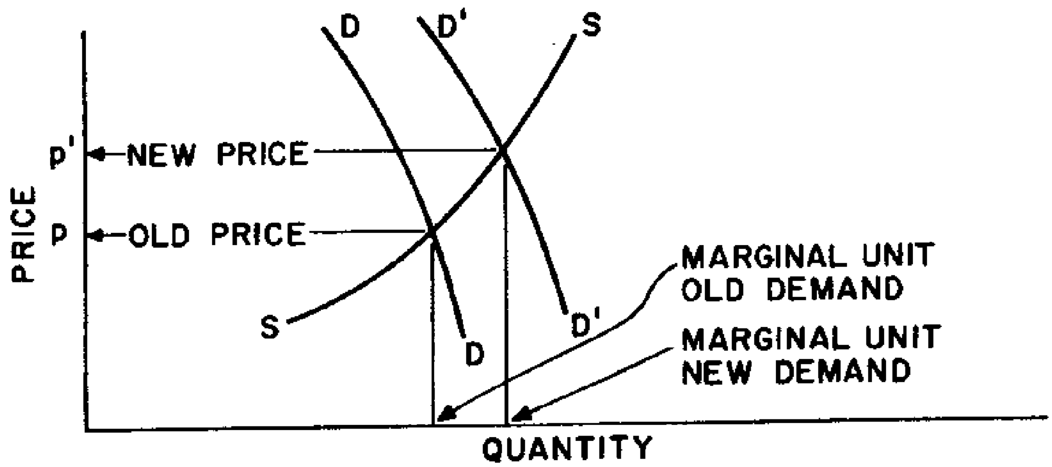

FIGURE I.3.3.a SHIFT IN DEMAND

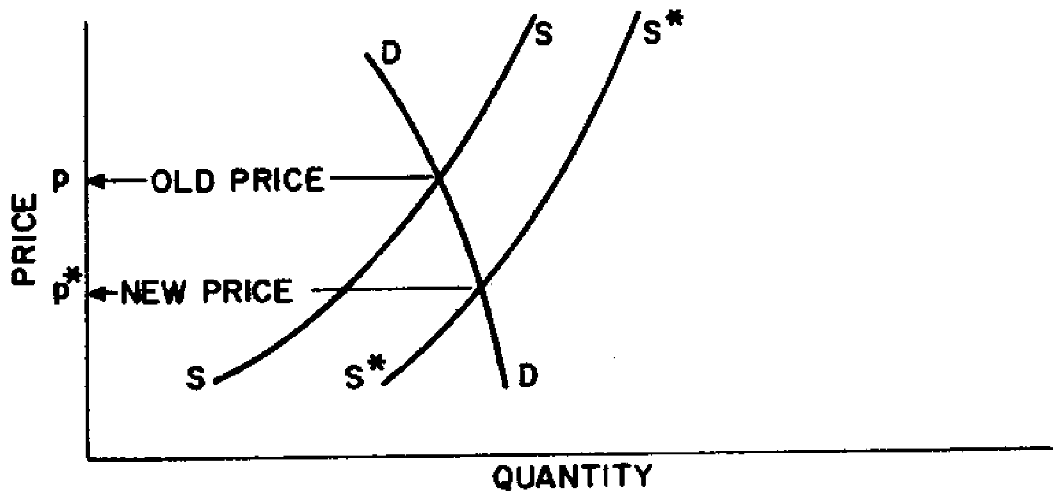

FIGURE I.3.3.b SHIFT IN SUPPLY

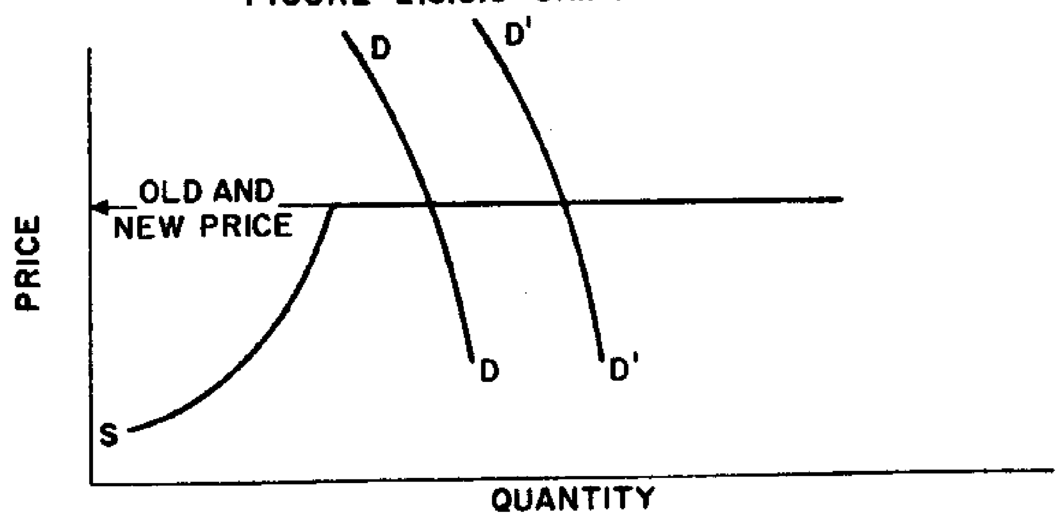

FIGURE I.3.3.c SHIFT IN DEMAND – NO PRICE CHANGE price from p to p*. Notice that in both cases, the price is determined by the investor's cost of the most costly barrel of oil actually exchanged. The investor's cost of this particular unit of oil is known as the cost of the marginal unit. In order to effect a change in price in a competitive market, you must change the cost of the marginal unit sold. For example, in Figure I.3.3c, the increase in demand from DD to D'D' will not change market price, for there is no change in cost of the marginal unit. The basic principle--in a competitive market, the change in market price equals the change in the investor's cost of the marginal unit sold--is central to our later analyses. As we shall see, it has some rather surprising implications. This principle has been incorporated in the petroleum development simulation program which, for each development hypothesis, estimates the investor's cost of the marginal oil and then prices the resulting products accordingly. The resulting market price changes are reflected in the regional cost estimates presented in Chapter I.8.

I.3.2 Assumptions used in computing investor's cost of marginal unit of oil assuming no Georges Bank petroleum

Consider for the moment a situation involving no Georges Bank petroleum development. The investor's cost of the marginal unit of oil delivered to New England will depend primarily on what combination of foreign crude pricing, f.o.b.,and federal import policy prevails. We have examined four cases with respect to these two variables:

1) No import quota - payments to exporting nations remain at 1972 levels;
2) Present federal import policy - payments to exporting nations remain at 1972 levels;
3) No import quota - payments to exporting nations escalate to $4.00/bbl (1972 dollars) in 1980, remain at $4.00 thereafter;
4) Present federal import policy - payments to exporting nations escalate to $4.00/bbl in 1980.

Because of the structure of the present federal policy, we will handle crude imports and resid imports separately.

Cases (1) and (3)present no conceptual problems. The marginal unit of crude will be imported from the Persian Gulf. There will be little change in the cost of the marginal unit with changes in amount consumed, for we will be on the horizontal portion of the supply curve, Figure I.3.2. The investor's cost of average quality Persian Gulf crude, f.o.b., we have put at $1.65/bbl under the assumption of no escalation in payments to exporting nations and at $1.65 (1972) to $4.20 (1980) under the assumption of escalated foreign crude payments. The simulation program delivers this oil to the specified refinery, whereupon it refines and distributes it just like any other oil for that particular development hypothesis. The total investor's cost of performing these functions, including all taxes, is computed from which the price required to return his cost of capital is calculated. This price is then applied to all the distilled products consumed within the region to obtain our estimate of the industry's gross revenues from these rates at the products reception port's loading flange. Notice that under these assumptions for the no import quota cases, the savings in national income due to differences in refinery location and products distribution system are passed on to the regional consumer. The situation is similar to that sketched in Figure I.3.4 which compares the East Coast landed supply curve for the present Delaware refinery with that for a 65' depth Delaware refinery. Chapter I.2 estimates the difference in landed cost of the marginal Persian Gulf crude is 29¢ per barrel which is reflected in a lowering of the horizontal portion of the supply curve. Under competition price will move from p to p*, the entire 29¢. A similar argument holds for the no import quota cases with foreign crude payments escalated. The absolute prices will be different but the change in price the same. Similarly, the effect of a change in the region's products distribution system will be passed on to the consumer under competition for it will lower the cost of the marginal oil.

Residuel fuel for those cases involving import of resid is treated in exactly the same manner except we have assumed that all the resid including the marginal unit comes from Venezuela. Due to the shorter route length and present draft limitations at the Venezuelan loading ports, the per-barrel savings associated with alternative products reception and distribution systems are generally smaller than the crude savings, about 5¢ per barrel for the 65' terminal off of Boston.

The cases involving continuation of the present import quota policy involve some conceptual problems. First, we

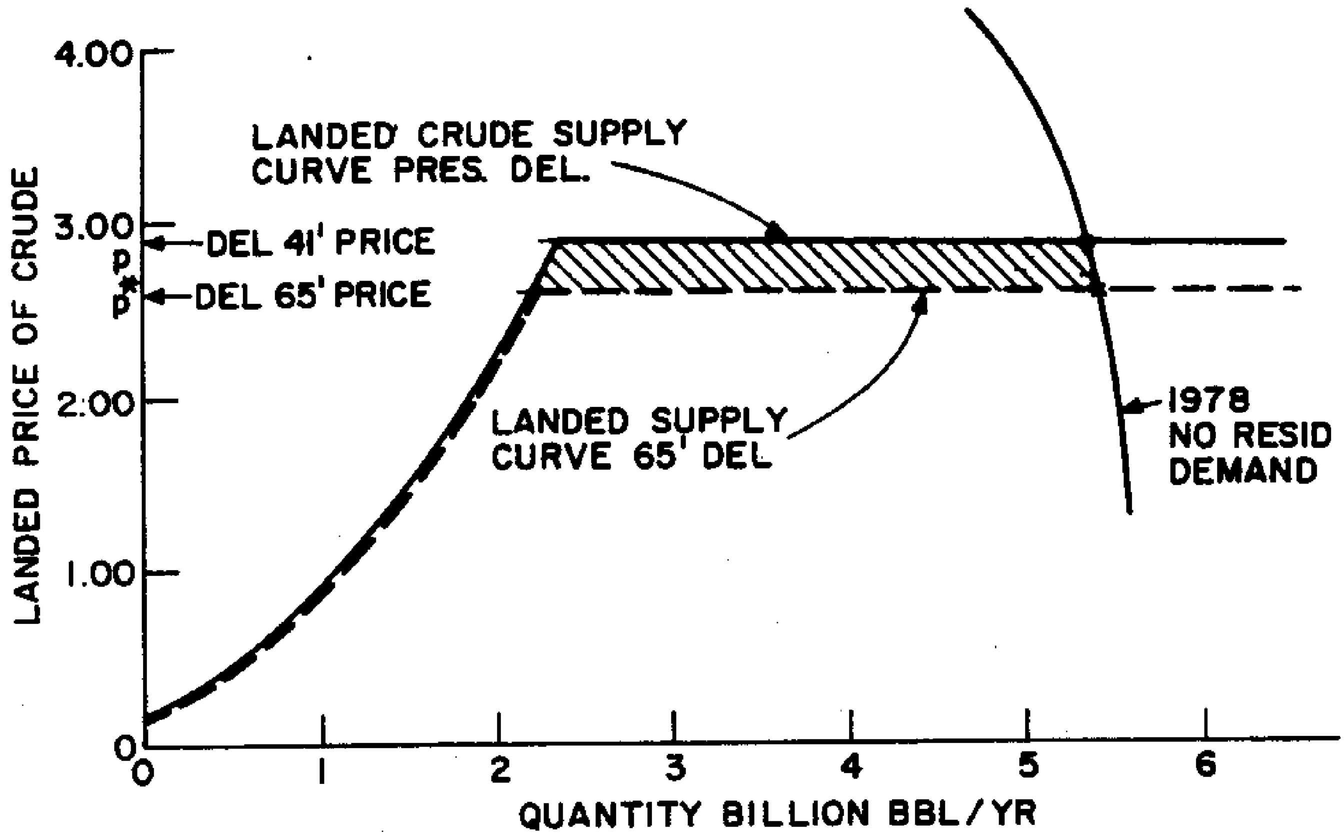

FIGURE I.3.4 SHIFT IN DIST. I-IV SUPPLY CURVE DUE TO SWITCH FROM 41' DEL. TO 65' DEL, 1978 @ 4% GROWTH RATE, NO IMPORT QUOTA

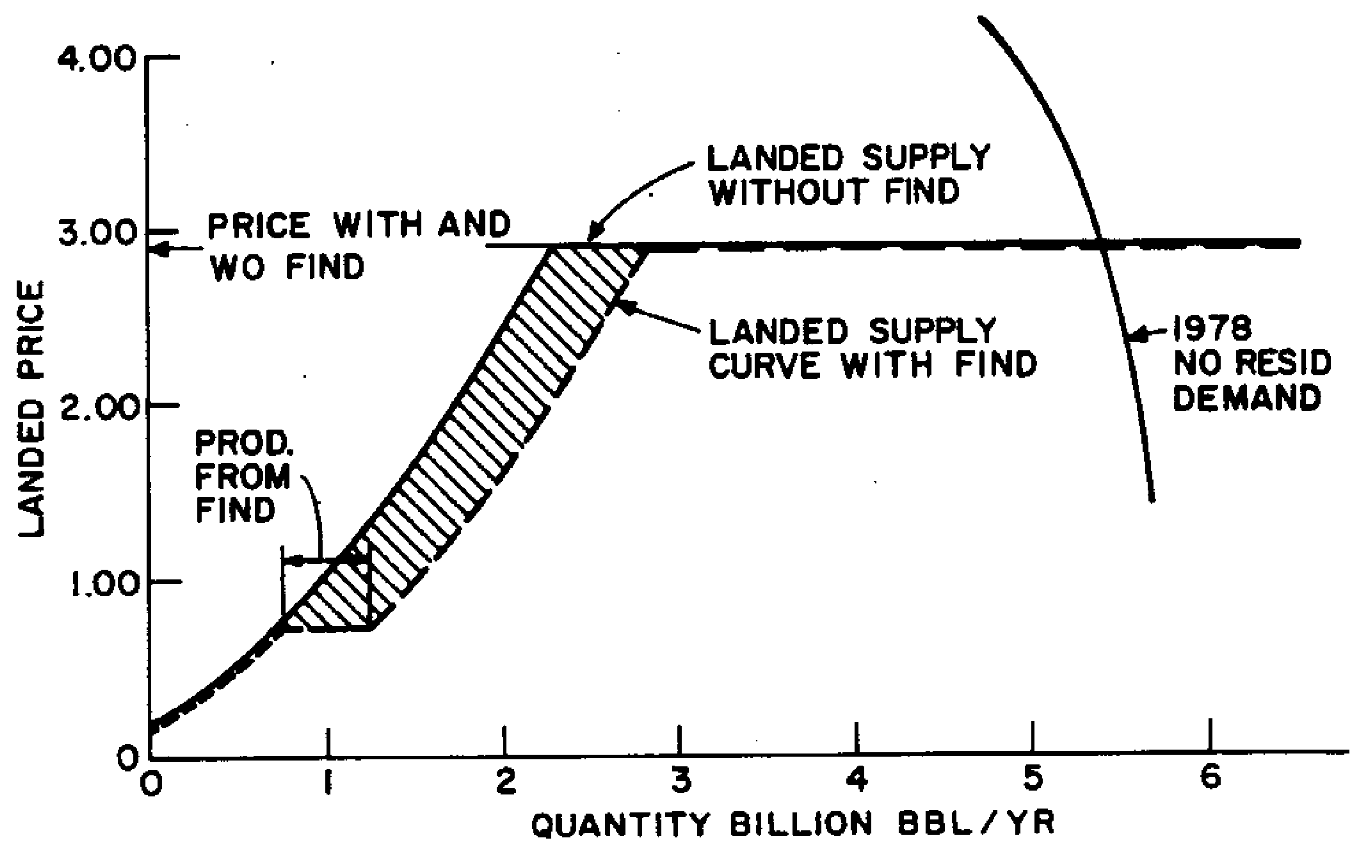

FIGURE I.3.5 SHIFT IN DIST. I-IV SUPPLY CURVE DUE TO GEORGES BANK DISCOVERY LANDING 500 MM BARREL PER YEAR AT PRES. DEL.

must define what we mean by the present import policy and second we must make an assumption about where the marginal unit of oil will come from under this policy. It is obvious that the U.S.A. no longer has an import quota in the text-book definition sense. For the last few years, quota alterations have increased in both frequency and magnitude to the point where any estimate of the amount of the present import quota will almost certainly be out of date by the time this report reaches the reader. Our problem then is to attempt to discern the policy governing these alterations.

This is not an easy task. It's not obvious in coherent terms that such a policy exists. The problem is further complicated by the fact that both the short-run demand and short-run supply curves are almost vertical, thus any shifts in supply induced by even small changes in the quota will result in large changes in price. (See Figure I.3.3b.) Finally, delays in the system prevent supply from responding in a smooth manner in the short run to a change in the quota. The resulting short-run dynamics makes the import quota a rather unsatisfactory instrument for controlling the system from a federal policymaker's point of view. He may be trying to do one thing with the quota (increase supply) and end up doing something else (decrease price), thereby hiding his motivations.

Nonetheless, the overall operation of the import quota policy over the last few years is not unconsistent with an objective of maintaining domestic crude prices approximately one dollar per barrel in excess of what they would be without the quota, that is, at maintaining import tickets at about their historic values. There are important exceptions. For example, ticket values have been allowed to drop during tanker rate booms. In fact, it is obvious that the actual operation of the quota is the result of a complex intermixture of shifting political forces. However, for the purposes of analysis, we will assume that the federal oil import policy is actually a price support policy which maintains average domestic crude prices about one dollar in excess of what they would be without the quota.

Specifically, we will assume that the marginal oil under the quota and no foreign crude payments escalation is Gulf Coast crude at $3.90 per barrel f.o.b. Louisiana. For the case with price escalation, we will assume the marginal oil is Persian Gulf crude, whose f.o.b. price is $1.00 in excess of the landed cost of foreign crude. Notice the assumption that the marginal oil under quota - no escalation is Gulf crude implies that only a portion of the savings due to changes in refinery location is passed on to the consumer in this situation, for the marginal oil will not obtain the same decrease in cost due to a deepwater refinery as Persian Gulf oil due to the shorter trip length and draft limitations in the Gulf loading ports.

I.3.3 The effect of a Georges Bank oil find on regional products prices

The foregoing section assumed no offshore oil discovery in investigating market price changes. However, exactly the same analysis holds with respect to those situations involving an oil find. This is demonstrated by Figure I.3.5, which compares the East Coast supply curve for the situation with and without a very large oil find (10 billion barrels in place) assuming no change in terminal draft limitations and no import quota. Chapter I.2 estimates this find will reach a maximum production of less than 500 million barrels per year and that the oil could be landed in Delaware at an investor's cost of about 80¢ plus royalties. Figure I.3.5 sketches the situation during a maximum production year. The find is equivalent to a rightward shift of the supply curve at the landed investor's cost. <u>The investor's cost of the marginal unit has not been changed</u>. Hence, under competition, market price will not be affected by the find. It would take a discovery large enough to displace all foreign crude in the eastern U.S. market before the discovery could affect price.* To the extent that the relevant markets are not completely competitive, this statement holds a fortiori. Notice there is a qualitative difference between the effect of a change in refinery location on products distribution system (Figure I.3.4) and that of a find (Figure I.3.5).

One type of change affects the cost of the marginal unit, the other does not. Even with the present quota policy, there will be no change in price, for the domestic

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*Actually, assuming a regional refinery, New England could appropriate to itself through price changes the <u>differential</u> in transport costs between transport to the regional refinery and the extraregional refinery if the find was large enough to supply <u>all</u> of New England's consumption. This difference will be quite small compared to the difference in landed cost and price less than 10¢ per barrel.

supply curve will still be steep enough to allow present price support policies to continue with almost no change, although the level of the import quota will have to be adjusted downward.* The situation under present policies and this find is shown in Figure I.3.6.

While we are on the subject of the import quota, it is perhaps worthwhile to examine Figure I.3.7. The shaded area is the increase in cost to consumers due to the quota resulting from the increase in price of the oil they consume with the quota. It is matched by an increase in producer and refinery income. Hence the shaded area does not represent a net loss in national income but a transfer from consumer to producer. The hatched area in Figure I.3.7, however, is a net loss in national income. The triangle on the left is the increase in cost to the nation due to the fact that we are consuming some domestic oil which is more expensive to produce than foreign oil. The triangle on the right is the increase in cost to the consumer resulting from the decrease in quantity consumed due to the increase in price. For example, consider a consumer who is willing to pay $3.50 for his unit of oil. He is represented at point y on the demand curve. At the with-import quota price he will forgo the consumption of this oil; without the quota he will obtain this consumption for which he was willing to pay $3.50 at $2.63 for a net gain to him of 87¢ per barrel. The rise in price associated with the quota forces him to forgo this gain.

The point is that the shaded area, plus the triangle on the right--the direct cost to consumers--can and almost certainly is much different in size than the hatched area -

*This statement depends on our definition of the import quota policy.

**Actually, the situation is somewhat more complicated than this. Some of this transfer is to Canadian producers and refineries and hence is a loss in U.S. national income. Some of the increase in price is returned directly to the public by means of increase in federal revenues, principally offshore lease payments.

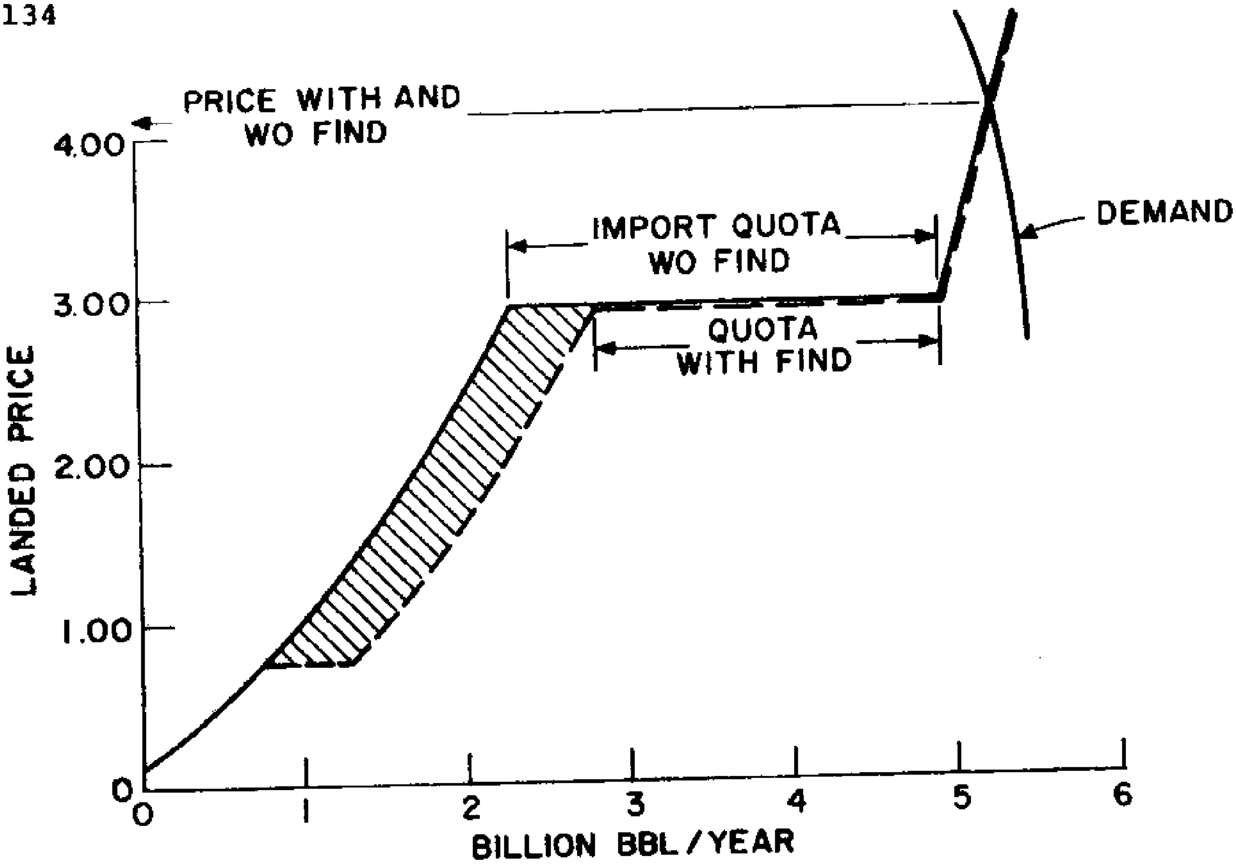

FIGURE I.3.6 SHIFT IN DIST I-IV SUPPLY CURVE DUE TO GEORGES BANK DISCOVERY UNDER ASSUMPTION QUOTA ADJUSTED TO MAINTAIN PRICE

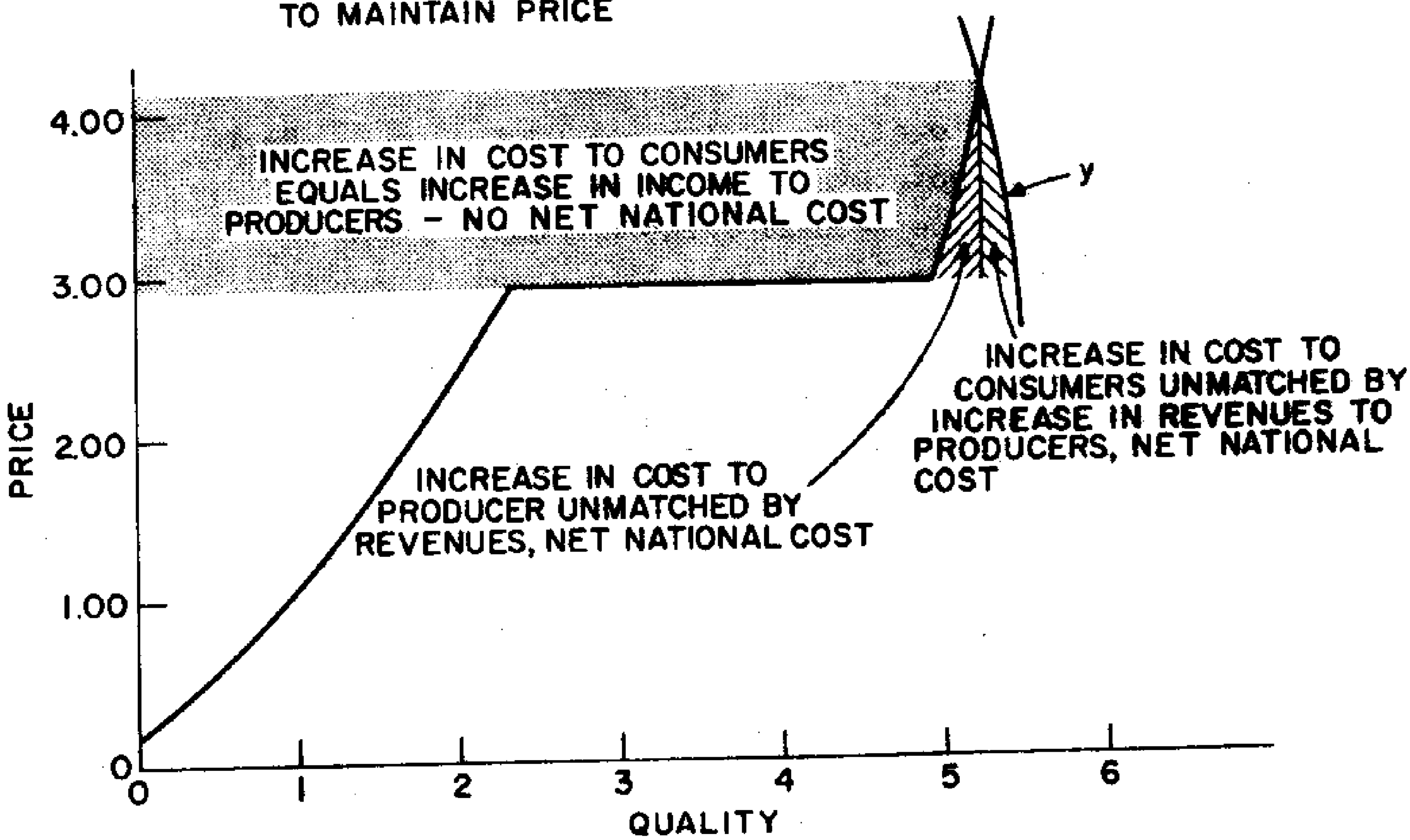

FIGURE I.3.7 DISTINCTION BETWEEN COST TO CONSUMER OF PRICE SUPPORT AND COST TO NATION the net cost to the nation. Thus, in discussing the quota one must be quite clear as to which definition of cost he is referring to.

Estimation of the crosshatched area depends on knowledge of the exact shape of the domestic supply and demand curves which we do not have. In Chapter I.8, we assume the curves are vertical over the relevant range. While this undoubtedly underestimates the national cost of the quota, it will have little effect on our estimate of the cost of the quota to New England, the great bulk of which is represented by the shaded area which we do account for.

I.3.4 <u>The impact of a gas find on the regional consumer</u>

The situation with respect to a gas find is considerably different, principally because of federal natural gas regulatory policies. Under present federal policy, the price of the bulk of natural gas delivered to New England distributors is held to about 45¢/Mcf (thousand cubic feet). There is clear evidence that at this price the amount of gas demanded by regional consumers is well in excess of the amount producers are willing to supply. Thus, we have roughly the situation sketched in Figure I.3.8, where consumption is held to approximately 220 billion cubic feet per year because the industry will not supply a greater quantity at the regulated price. The excess of demand over supply at the regulated price is given by the length of the line S_1S_2. Our study does not involve an energy demand analysis, so we do not have an estimate of the actual size of S_1S_2, nor the shape of the supply or demand curves. The forthcoming New England Energy and Power Study should shed light on these issues. Whatever this excess, a non-price mechanism for rationing out the available supply of gas among the demanders must be found. Presently, this mechanism generally takes the form of no-new-customer rules even when the prospective customer is willing to pay more than the market price for the gas. Now assume for the moment a 5 trillion cubic foot gas discovery. Chapter I.2 estimates that such a find will have a maximum yearly production of about 700 billion cubic feet, which could be landed at an investor's cost of about 25¢/Mcf plus royalties (no oil). The effect of such a find on the region's gas supply curve is indicated in Figures I.3.8 and I.3.9. Our analyses consider two possibilities with respect to natural gas pricing:

1) Present regulatory policy: gas is priced at approximation of the rate required to yield

the investors their cost of capital on the discovery. Price of presently imported extraregional gas is unaffected.

2) Deregulation: price rises to competitive market equilibrium.

Figure I.3.8 outlines the main features of the first case. The entire crosshatched area, A and B, will be an increase in consumer income, for consumers who are willing to pay the amounts indicated by the demand curve will obtain the gas at 25¢ city gates.* If the gas were priced at the present New England city gate price, about 45-50¢/Mcf, then the area A would be an increase in consumer income, area B an increase in producer income, some of which might return to New England in the form of increased lease payments. See Chapter I.4.

Under deregulation, the price would rise to the intersection of the supply and demand curve, hypothesized to be 67¢, in Figure I.3.9. In this case, area A would be an increase in consumer income due to the fact that consumers who are willing to pay more than 67¢ for the gas, because it would cost them this additional amount to obtain their energy from other sources, or, alternatively, to forgo consuming this energy, obtain it for 67¢. Area B would be an increase in public and private producer income.

Notice that the sum of the areas A and B is higher under deregulation than regulation, indicating that national income will be higher under deregulation. However, regional income will generally be higher under present regulatory policies unless almost all the increase in national

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*Assuming, of course, that the distributor obtains no more than his cost of capital for distributing the gas. This is approximately what would happen under present utility regulation.

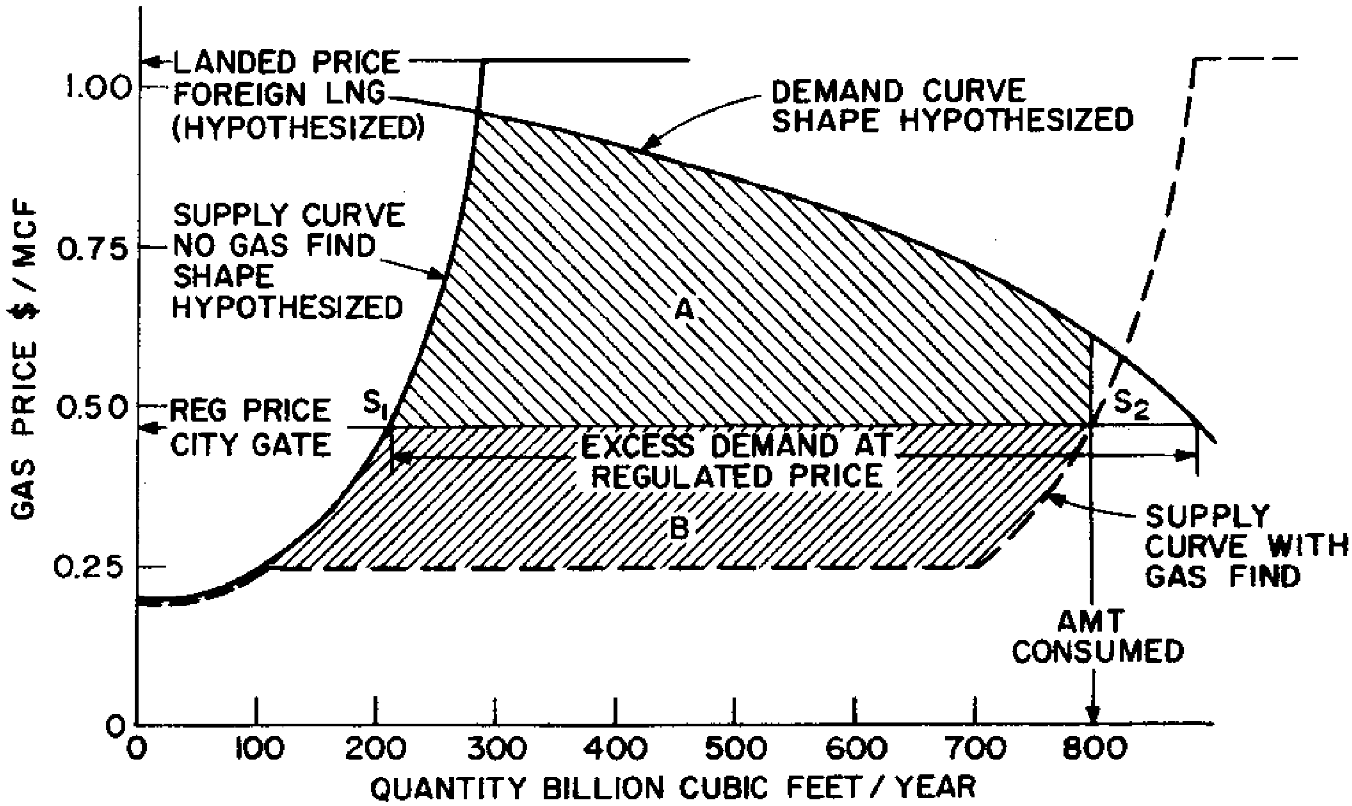

FIGURE I.3.8 GAS SUPPLY AND DEMAND SITUATION WITH AND WITHOUT 600 BILL. CU FT/YEAR FIND, PRESENT REGULATORY POLICY

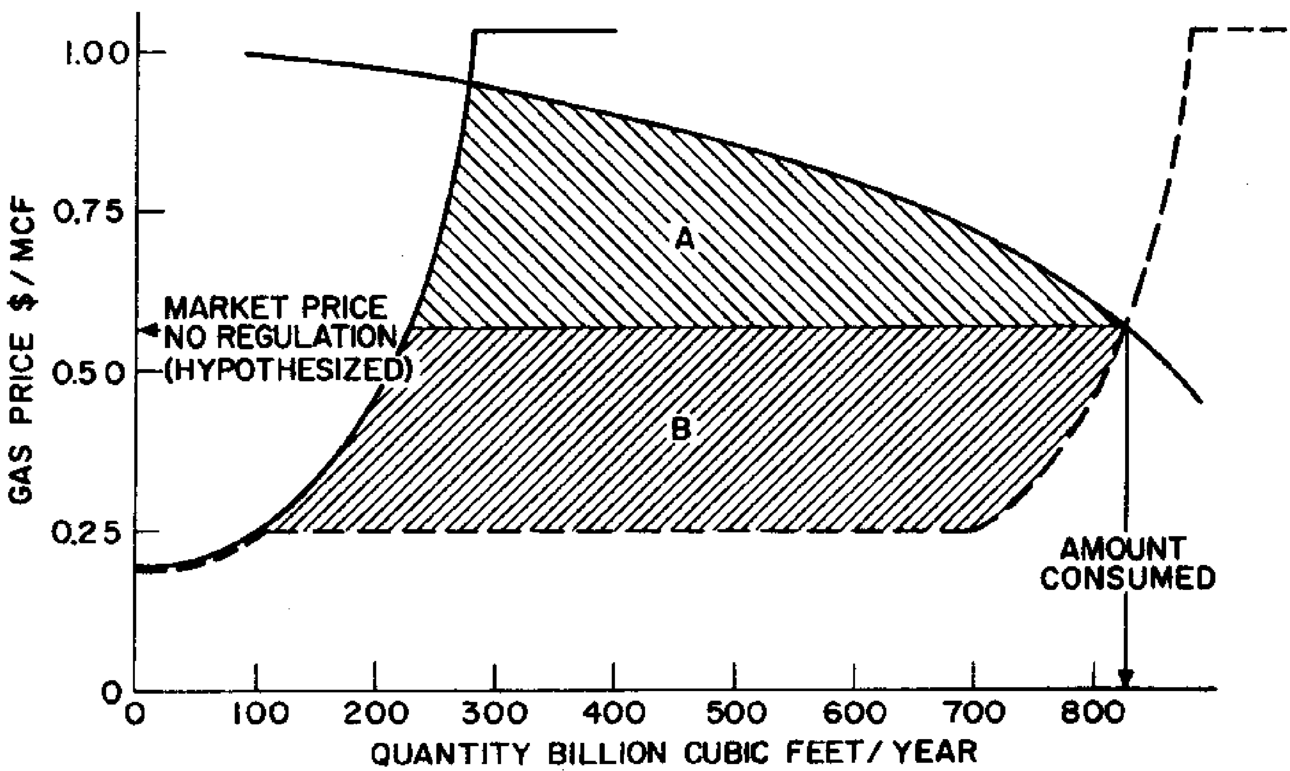

FIGURE I.3.9 SAME AS ABOVE, EXCEPT DEREGULATION OF NATURAL GAS PRICES producer income accrues to the region. There is one exception to this: if a small gas find were discovered, say one for which the landed cost was 60¢/Mcf, yet regulatory policy held the market price below 60¢. then this gas would not be landed and the regional consumers would be out the difference between what they would be willing to pay for this gas and 60¢.

Since we don't know the slope of the demand curve, we can't strictly speaking compute the areas A and B under the various pricing schemes. However, a conservative estimate can be arrived at by assuming that any landed Georges Bank gas displaces residual fuel oil, on an energy-equivalent basis. Actually, this gas will be used in some combination of the home heating (displacing distillates) and resid markets. Since the region consumes about 800 trillion BTU's in both these markets, either market could conceivably absorb the bulk of the maximum production of a 5 trillion cu ft find. Assuming all gas goes to the resid market is conservative in that this is the lower valued use and further does not give the gas complete credit for its low sulphur content (Chapter II.8) since our resid costing (Chapter I.2) is based on .5% sulphur resid. In actuality, the gas would begin by displacing very low sulphur resid. Thus, the increase in regional income associated with the gas find arrived at by our assumption is a lower bound. The above principles have been incorporated in the petroleum development simulation program and are reflected in the changes in regional income presented in Chapter I.8.

I.3.5 The degree of competition in regional products markets

At this point, it may be worthwhile to re-examine our assumption of pure competition in the liquid products markets. The three principle markets are: residual fuel oil, distillate fuel oil, and gasoline. Listed in this order they exhibit an increasing divergence from our text-book definition of competition - no single buyer or seller can influence market price.

We have uncovered no evidence to suggest that the residual fuel market is not for all practical purposes purely competitive. While it is true that the sellers are dominated by about eight majors, the buyers (the utilities) are individually strong, well-informed shoppers who can obtain their needs from a large number of alternative sources if local suppliers do not offer competitive prices. (They are often dealing with shipload consignments.) Prices are relatively flexible and respond readily to changes in supply and demand. Price levels are explainable in terms of marginal costs. The price decline which followed the removal of import restrictions on residual in 1966--from over $2.00 per barrel in 1966 to $1.60 per barrel in 1969--is a positive indication of the response of price to changes in marginal cost in this market.*

The case of the distillate fuel market is less clear-cut. There is considerable imbalance between the few sellers and the large number of buyers or jobbers. There is some branding although it doesn't appear to be very effective and even branded jobbers sometimes change suppliers in their search for the major offering the best price. Prices are explicitly set by the majors and do exhibit some inflexibility. On the other hand, real distillate supply and demand and price levels do appear

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*The price adjustment was delayed by the 1967-1968 tanker boom. In terms of constant value dollars, this was a 33% decline in real price.

consistent with marginal cost. Some independent jobbers have considerable storage capacity and are in a position to shop almost around the world for their supplies, at least theoretically. The principle impediment here is the import quota and the short time interval between the granting of additional import tickets and when the fuel is actually needed. With our present state of knowledge, the best guess appears to be that, while it is certainly not textbook competition, the majors would have considerable difficulty maintaining distillate fuel prices in the face of a significant decrease in marginal cost. Removal of or more efficient regulation of the import quota policy would allow us to strengthen this statement.

The gasoline market is further from pure competition still. The majors are vertically integrated down to the retail level controlling prices directly in 80% of the retail market.* Brand preferences in the consumers can be and are being maintained by intensive advertising to the point where consumers will pay up to 5¢ per gallon premium to buy the same product from a major. Most damaging of all, in the three or four months prior to price control, wholesale gasoline prices rose an unprecedented 3-4¢ on the average across the country.** No evidence has been offered that this price change can be explained by supply or demand shifts. Some observers have ascribed this price rise to foreknowledge on the part of the industry of price and wage control. If this is the case and if the suppliers did have the ability to cut on this knowledge, then the market is certainly not competitive, at least in the short

*Branded, "independent" station owners generally lease their stations from the major. The terms of the lease are in ¢/gallon.

**The average pre-tax retail price of gasoline rose from 22.12 cents on July 20, 1971 to 23.44 cents a week later and to 26.18 cents on August 3. The freeze was announced on August 14. (Journal of Commerce, Dec. 27, 1972).

run. Price flexibility appears to depend critically on the particular urban market under consideration, fluctuating by as much as 8-9¢ a gallon on a monthly basis in cities such as Oklahoma City, while rarely changing in New York City. This is clearly an extremely complicated market and we have not undertaken the analysis which would allow us to predict to what degree decreases in marginal costs will be reflected in price decreases. However, there is evidence that at least some of the long-run marginal cost decrease will be passed on. Long-run wholesale gasoline prices have not in general been out of line with long-run marginal costs. Buyers are becoming increasingly advertising-resistant. Independent outlets are increasing market penetration. The market share of the ten largest retailers in Massachusetts has declined from 88% in 1960 to 80% in 1970, and, at least in some cities, the majors have been forced to respond to these pressures. Unless the majors can control refinery production to the point where they can shut off the independent retailers' supplies, something they have not done as yet, prices in the extremely competitive independent market will respond to changes in marginal costs, which will attract additional business with consequent downward pressure on major outlet prices. In short, it is quite possible that a good part of the decrease in marginal cost will be passed on to gasoline consumers. It is interesting to note that the average retail pre-tax price in New Orleans for 1972 is about one cent a gallon lower than the average price in Boston, which is about the cost of transporting a gallon of gasoline from the Gulf Coast to New England.

In summary, in Chapter I.8 we will assume that all regional products markets are essentially competitive. There is solid evidence that this is the case with respect to residual fuel, and it appears to be the case, for practical purposes, for the distillates market. It is least true for gasoline. However, there is a good chance that the bulk of long-run decreases in the delivered cost of marginal oil will be passed on. To the extent that this doesn't happen, the Chapter I.8 numbers will be biased in favor of those development hypotheses which by means of refinery location or products distribution system changes lower the investor's cost of delivered gasoline.

I.3.6 The Relationship between Payments to Exporters and Transport Costs

Finally, we must emphasize an extremely important assumption which has crept into our analysis. We are operating under the supposition that the payment to the exporting country for imported oil is independent of the transport cost of landing the oil. If the market between the oil companies and the exporters were competitive this would be true. One of the basic results of transport economics is that an importing nation, whose demand is insensitive to price importing from a foreign supplier whose supply curve is essentially horizontal, bears the entire cost of transportation. The f.o.b. price of the export will not change with a change in transport cost. Thus, any decrease in transport cost accrues entirely to the importing nation.

Unfortunately, as pointed out earlier, the exporter-company market is far from competitive. If we assume the other extreme, a unilateral seller's monopoly, the income maximizing monopolist would increase his price by the decrease in landed cost, appropiating the entire increase in world income to himself.

What we actually have is an organized sellers' cartel facing an unorganized buyers' cartel in a situation which is basically a bilateral monopoly. Given this situation and given our lack of knowledge about the efficacy with which the buyers will develop their bargaining position, it is simply impossible to say whether improvements in transport systems will affect the f.o.b. cost. However, unless the market nations do a better job with respect to developing their position, our arguments about whether or not the consumer or the company will see the increase in income due to a deepwater port may very well be academic. For this increase will quite possibly be transferred to the exporters.

Chapter I.4
Treatment of Private and Public Profits

I.4.1 Introduction

As indicated by the supply curve analysis of Chapter I.3, a large portion and in some cases all of the increase in real national income resulting from a discovery on the Georges Bank will accrue to the public and private entities which control the resource at its source. The purpose of this chapter is to discuss our treatment of how this increase in national income will be divided between private investors and public bodies, and, more importantly for our purposes, between the nation and the region. In addition, we will outline our treatment of the overall profits which accrue to the investor in all phases of the provision of oil to New England and the effect of federal and regional taxes paid by the investor.

I.4.2 The no offshore discovery case

Let us begin our discussion of profits and public revenues for those situations involving no offshore discovery. The entire system delivering, processing, and distributing oil to New England is treated as if it is owned by a single American corporation. The computation of the federal and regional tax payments of this corporation is the function of the subroutine PROFITS.

PROFITS obtains the gross revenues of this corporation by estimating the cost of marginal crude and resid for the hypothesis under analysis. In so doing, it makes the following assumptions:

1) NO IMPORT QUOTA - NO FOREIGN CRUDE ESCALATION
Marginal oil is Persian Gulf crude at $1.65 per barrel at loading port. For NORESID option, marginal residual oil is .5% sulphur Venezuelan resid at $3.10 per barrel at loading port.

2) NO IMPORT QUOTA - FOREIGN CRUDE ESCALATION
Same as (1) except crude cost f.o.b. rises to $4.20 per barrel in 1980. Resid cost rises to $5.55.

3) IMPORT QUOTA - NO FOREIGN CRUDE ESCALATION
Marginal oil is Gulf Coast crude at $3.90 per barrel in Louisiana. Resid same as (1).

4) IMPORT QUOTA - FOREIGN CRUDE ESCALATION
Marginal oil is Persian Gulf crude but price support policy maintains prices $1.00 in excess of crude price in (2). Resid same as (2).

The program then adds to the investor's cost of this crude at its source the investor's cost of delivering it to the specified refinery, processing, and distributing it, which costs will depend on the development hypothesis currently under analysis. It then prices <u>all</u> the distillates sold in the region at this total cost.* A similar set of computations takes place for resid for those cases in which residual fuel is assumed to be imported. These two figures determine both the direct cost to the regional consumer (before secondary redistribution, highway taxes, etc.) of their consumption of oil and equivalently the gross revenues of the corporation supplying this oil.

PROFITS then applies standard American tax law to these revenues. In so doing the following additional assumptions are made. The industry reports its "ad valorem" taxes are running at about 10% of gross before tax outlays exclusive of foreign taxes, lease payments, royalties and interest. Presumably this figure covers property taxes, sales and excise taxes, permit fees, etc. So far as income taxes are concerned, this item is treated as an operating expense. If the refinery is in the United States, it is assumed that the federal share of these outlays is 40%; otherwise the federal share is put at 10%. If the refinery is in New England, it is assumed that the regional share of these outlays is 40%; otherwise the region's share is put at 10%.

Federal income taxes are computed at 48% on net taxable income after deductions for operating expenses, interest payments, depreciation, depletion, and tax loss carryovers (five year maximum). Payments to exporting country are treated as a direct tax credit. As a result, the corporation rarely pays any U.S. income tax. Regional income taxes are based on Massachusetts corporate tax laws with no deductions for depletion.

Having estimated the corporation's tax payment, the program computes the present value of all the corporation's

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*This will be the long-run average price of all New England distillate products (gasoline, home heating oil, etc.) at the entrance to the products reception terminal under competition. The program makes no attempt to estimate the individual price of each product.

actual cash outlays including taxes, capital expenditures, and payments to creditors at the investor's cost of capital. This is deducted from the present value of the corporation's revenues to determine the company's profits. This definition of profits implies that if profits are equal to 0, the corporation is earning a return on equity capital just equal to the investor's cost of capital. Thus, 0 profits does not imply the firm is making no money but rather that it is making no more money than it would have made if its equity capital were invested elsewhere. A positive value of profits, then, is a true increase in the real income of investors associated with the existence of the development hypothesis under analysis.

At this point, subroutine PROFIT has computed four numbers:

1) direct cost to regional consumer = gross revenues
2) investor profits
3) federal revenues
4) regional revenues

For the no-offshore-discovery cases, our estimate of the cost to the region of obtaining its oil consumption is based on the following expression:

REGIONAL COST = CONSUMER COST
- .05 (INVESTOR PROFITS & FEDERAL REVENUE)
- .50 (REGIONAL REVENUES)
- Correction for Difference Between Regional Wage Rate and Regional Cost of Labor

The first term on the right-hand side is the direct cost to New Englanders of consuming the oil. The second term is an estimate of the region's share of private profits and federal revenues where we have assumed New Englanders represent 5% of the ownership of the corporation based roughly on the region's share of national wealth. Similarly, we have assumed that 5% of the federal revenues accrue to

New Englanders or equivalently New Englanders pay 5% of the nation's federal taxes which are reduced by the above revenues. The next term assumes that the regional revenues generated by the development (property taxes, state income taxes, etc.) are double the regional public costs associated with the development (additional streets and sewers, additional police and firemen, regional revenues associated with alternate uses of the land used by the development, etc.). A study by the University of Rhode Island of a Rhode Island refinery proposal indicated that regional public costs may be higher than 50% of the revenues (Mlotok, 1970). However, since regional revenues for the no-offshore cases are quite small compared to the other regionwide numbers with which we will be dealing, it doesn't make too much difference what percentage we assume. These revenues may, however, be large to the municipality in which, say, the refinery is located. Thus, from the point of view of municipal income, much more detailed analysis is called for.

The final term is a correction for overpricing of regional labor if there is unemployment. This correction is discussed in the next chapter. For full employment, it would be zero.

The assumption of a single corporation is simply a computational convenience. Under U.S. tax laws, if this corporation were divided up into a number of smaller companies, all of which were profitable, these smaller companies would pay in toto approximately the same taxes as the single larger company.

I.4.3 Treatment of offshore profits and public revenues

The private profits and public revenues associated with a given Georges Bank discovery and refinery location and their incidence will depend on:

a) whether or not there is escalation in foreign crude and resid prices;

b) whether or not the import quota is in effect;

c) whether present gas regulatory policy or deregulation is in effect;

d) whether the nation or the region controls the Bank;

e) amount of offshore lease payments and royalties.

Assume for the moment that lease payments and royalties are fixed at some specified set of values. And consider first a situation in which no gas is landed from the discovery. For each of the above 16 combinations of policy variables Georges Bank oil is landed at the specified refinery according to the least costly (tanker or pipeline) transport system as determined by OFFSHOR. This oil is processed and distributed in exactly the same manner as the foreign crude which is landed at this refinery, and sold at the cost of the marginal unit of oil. The amount of foreign crude imported in each year is reduced by the amount of offshore production. Chapter I.3 argued that it would take a find large enough to displace all the foreign oil on the East Coast before the cost of the marginal unit of oil will be affected by the find. Thus, in our analyses, the offshore oil itself does not affect the market price of the final products or the gross revenues of the corporation. However, it will affect the investor's overall cost by replacing some of his foreign crude outlays with the outlays associated with the find. The program simply recomputes the investor's cost with the find including offshore lease payments and royalties and calculates the corporation's overall profits in exactly the same manner as before, adjusting depreciation and depletion and tax credits according to American tax law. This computation also produces the present value of the leases and royalty payments to the public owners of the Bank. These profits are treated in the same manner as before - five percent is assumed to accrue to New England shareholders. For the situation in which the nation controls the Bank, these public revenues are treated in exactly the same manner as the federal revenues in the no-offshore case, that is to say they are treated in the same manner as any federal revenues - the region sees 5% of the amount of these revenues. For the situation in which the region controls the Bank, regional cost is reduced by the full amount of these revenues on the grounds that the regional public cost associated with the offshore activity itself is a very small proportion of these revenues.* See Chapter I.5 for a brief discussion of the amount of shoreside activity which we think will be generated by a discovery.

The situation with respect to offshore gas is slightly more complicated. The basic assumption used is that the gas, if landed, will replace .5% sulphur resid in the utilities and industrial space heating market. This is conservative with respect to the value of the gas for at least some of this gas will go to higher valued uses, especially if the quota remains in effect. The value of the resid replaced will in turn depend on foreign crude price, the products distribution system hypothesized, etc. The program's first step in analysing a gas find is to determine whether or not the gas found will be landed. To do this it compares the present valued cost to the investor of building a minimum cost gas pipeline to the present Algonquin trunk line plus gas royalties with the revenues

*This statement refers to market costs only. For costs due to environmental effects, see Chapter I.6.

the investor will receive for this gas.* These revenues in turn depend on the gas pricing policy in effect as well as the value of the resid replaced. Under the deregulation hypothesis, the gas is priced at the landed cost of the resid on an equivalent BTU basis. Under the present regulation hypothesis, the gas is priced at 30¢ per thousand cubic feet on the grounds that present regulatory policy would be loath to peg what is essentially a wellhead price any higher than this. The actual value of 30¢ is arbitrary, however, and can be varied as desired. It was chosen to demonstrate the main implications of the present gas pricing policy as compared to deregulation. If the present value gas revenues are higher than the cost of the pipeline plus royalties, the gas is shipped to shore.

If the gas is shipped to shore, consumer cost is adjusted downward by the difference between the landed cost of resid and the gas price on an equivalent energy basis. This difference will be zero in the case of deregulation for the gas will rise to the cost of the resid. All the increase in income associated with the gas, under this set of assumptions, will go to public and private profits. Under present regulatory policies, this difference will be the landed cost of resid minus 30¢ on an equivalent BTU basis times the present value of the amount of gas landed. Public and private profits will decrease accordingly. In either case, the public revenues and private profits associated with the gas are treated in exactly the same manner as those associated with the oil.

This leads to some interesting situations. Generally, if the region doesn't control the Bank, it is better for the region to be operating under the present gas regulatory

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*That is, we are treating outlays associated with production facilities and lease payments as sunk, which they will be, except possibly for an all-gas, no-oil find.

policy. However, if the resulting gas price is such that the gas will not be landed when it would have been landed under deregulation, regional income is increased by moving toward deregulation. One has to be careful not to price tha gas too low or set the gas royalties too high. If the region controls the Bank, regional cost is for all practical purposes insensitive to gas regulatory policy as long as the gas is landed. The effect of the gas policy in this case is to transfer income from regional consumer to regional taxpayer or vice versa.

I.1.4 Lease and royalty payments

We have seen that a key variable in determining the incidence of the increase in national income associated with an offshore find is the portion of this increase which the investor turns over to public bodies in the form of lease and royalty payments. In order to determine what proportion was likely to accrue directly to public bodies, we examined the U.S. Outer Continental Shelf experience through 1971. According to Geological Survey records, OCS lease payments for the period 1954 to 1971 totaled 5.47 billion (1972) dollars.* Oil royalties in this period totaled 2.29 billion, and gas royalties, rents, and shut-in payments .089 billion. The present value at 10% cost of capital of these payments was compared with the actual oil and gas production through time during the period and those combinations of oil and gas price which would just pay the investment in leases and royalties off at 10% determined. The results are shown in the upper line in Figure I.4.1. If the price of gas were zero, the investor would have had to receive an average price of $3.17 per barrel (1972 dollars) at the time the production was sold to make 10% on his investment in lease and royalties. If the price of oil were zero, he would have had to receive 51¢ per Mcf to pay off the investment. This computation assumes that the pre-1972 leases stop producing in 1972, which is clearly unrealistic. However, even if one assumes that the pre-1972 leases produce at 1972 levels for twenty years, which is clearly overly optimistic, then through the entire 1954 to 1992 period, the investor would have to receive the prices shown in the lower line to make 10% on his investment in leases and royalties. This line assumes present offshore royalties are applied to the 1972 through 1992 production. We can be fairly comfortable

*Pre-1972 payments inflated on the basis of the GNP deflator.

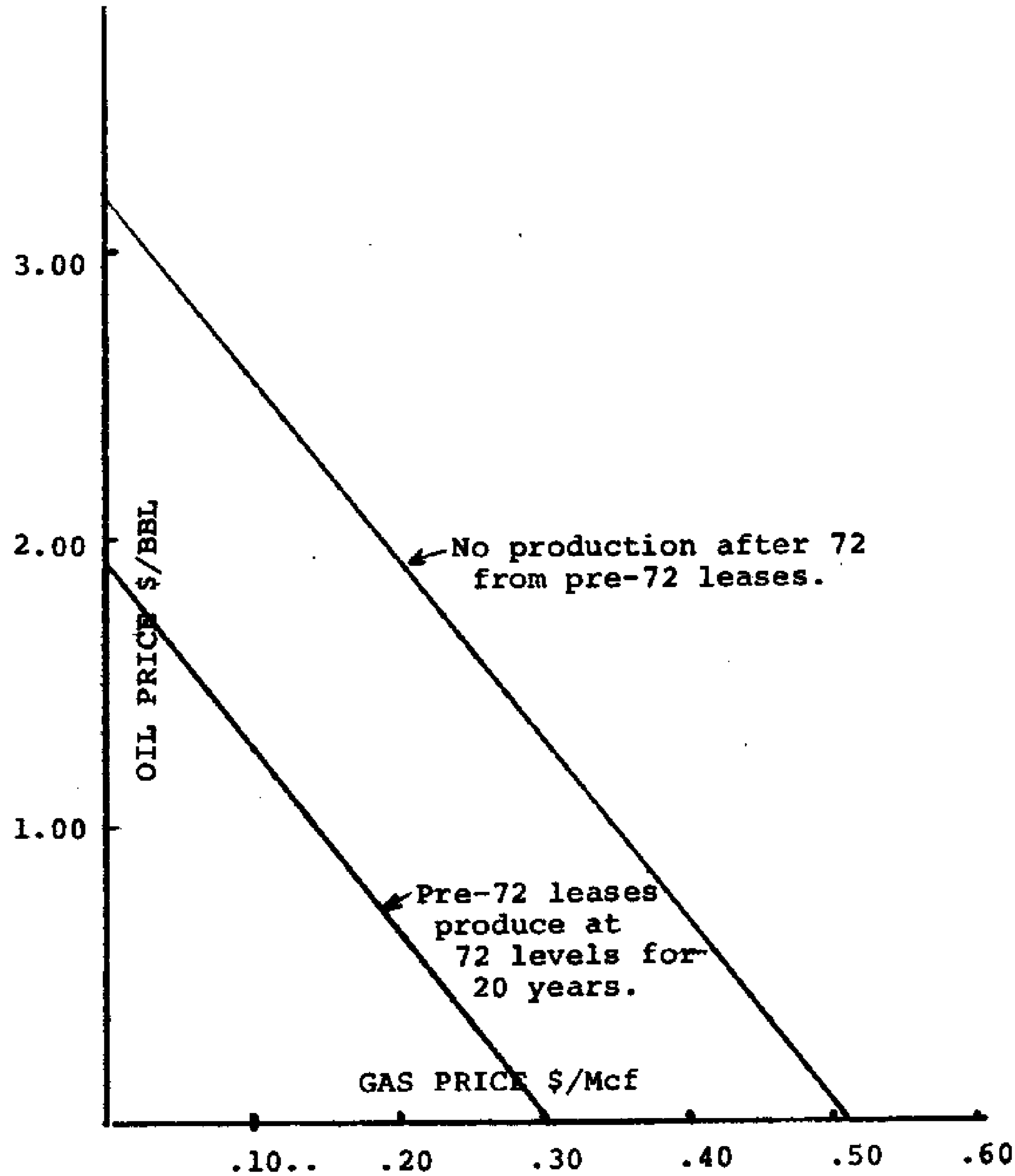

Figure I.4.1 BREAKEVEN OIL AND GAS PRICES REQUIRED TO PAY OFF OCS LEASES AND ROYALTIES AT 10% COST OF CAPITAL.

that the two lines bracket the possibilities with respect to future production from these leases.

However one looks at Figure I.4.1 it appears quite obvious that the federal government is appropriating directly to itself a large share of the difference between the national cost of offshore petroleum and the price it is sold at. The industry claims that the average barrel of Gulf Coast oil costs them about $1.50 to land. Our reservoir model indicates this might not be far from the truth, for most of the Gulf of Mexico fields are quite small by our standards, the technology used in exploiting them is on the average considerably less efficient than that available today, and the industry is working with what appears to us to be inefficiently low allowables in the Gulf. If this is the case, then with gas priced at about 20¢ at the wellhead the industry would have to receive between $2.25 and $3.50 per barrel landed to break even at ten percent.

There are several obvious implications of this result:

1) If the import quota were abolished and the price of domestic crude dropped to the neighborhood of $2.75, as it would if the market nations were able to hold payments to foreign exporters constant, an awful lot of the investment in OCS leases is going to look pretty bad.

2) To put it another way, the public is receiving a portion of its loss due to the import quota back in the form of higher lease bids than would take place without the quota.

3) This returned portion is small compared to the overall consumer loss due to the quota. However, if foreign crude prices do not rise, it may be necessary to renegotiate lease payments to abolish the quota. On the other hand, if foreign

crude price escalates, the industry will make a handsome profit on its investment in the Gulf regardless of whether or not the quota is abolished.*

4) The industry claims that it is not making any money on offshore oil and our contention that offshore oil can be quite cheap may, at least with respect to the Gulf, not be contradictory.

However, for our purposes, the important point is this. It appears possible through the medium of competitive bidding for the public body controlling an offshore petroleum resource to appropriate the bulk of the difference between the market value of the landed petroleum and the resource cost of landing that petroleum to itself. From the point of view of national income, this is not all that important for the result is merely a transfer from one set of Americans (oil company shareholders) to another set (the federal taxpayer). From a regional income point of view, it is all-important if the region controls the Bank, for the region will see only a small (about 5%) share of the increase in oil company profits due to the find unless the region owns the company exploiting the Bank while it sees all of the payments to regional public bodies.

The foregoing is a strong argument in favor of competitive bidding from the point of view of the owner of the resource. It is even a stronger argument when this history is compared with, for example, the Norwegian "nominal rent - most extensive work program" policy. The Norwegian people will see a very small share of the increase in world income resulting from the Ekofisk find. Other advantages are that it is inherently harder to corrupt than the Norwegian system and less prone to coziness between regulator and regulatee than such things as public-private partnership. Preventing collusion in bidding is, of course, crucial.

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*This fact has obvious implications with respect to the present market nation policy of allowing the oil companies to negotiate the price of OPEC crude for them.

On the basis of the foregoing, the lease payments in the runs displayed in Chapter I.8 have been set so that the bulk of the difference between the cost of landed offshore oil and its market value landed, the increase in national income associated with the find, accrue to the public body controlling the resource in situ. This assumes informed, intelligent pricing of the resource. The program accomplishes this by comparing the present value of the market value of the offshore crude landed at the refinery plus the revenues the developer will see from his offshore gas (if gas is landed) with the present value cost of producing this petroleum including royalties and assigns a specified percentage of the difference to the public body controlling the Bank in the form of lease payments. For the runs displayed in this report, this percentage has been set at 75%. Royalties have been set at 45¢/bbl oil and 12.5% market value for gas. Notice the lease payments so computed will depend on foreign crude cost, import quota, and gas regulating policy as well as the amount of oil and gas found. This assumes a high degree of knowledge on the part of both lease bidders and the public body of not only the discovery but also the future values of these variables.

Mlotok, P. "A Study of the Economic Implications of the Refinery Proposed for Tiverton, Rhode Island." U.R.I. Occasional Paper, 70-345, December, 1971.

U.S. Geological Survey, Conservation Division. "OCS Oil, Gas, Sulphur and Salt, Leasing, Drilling, Production Income and Related Statistics, 1971.

Chapter I.5
The Impact on Regional Income of Employment Effects Associated with the Hypothetical Developments

I.5.1 Introduction

All our analyses so far have operated under the assumption that the market wage rate of regional labor employed by the development being investigated is equal to the loss in regional income associated with transferring this labor from whatever it would have been doing in the absence of the development. This loss we have termed the regional cost of labor. In short, we have assumed that each man's pay is equal to the market value of what he could produce elsewhere. Under this assumption there is no net gain in real regional income associated with the payroll of a potential development.

This would be the situation if regional labor markets were purely competitive.* Under pure competition, if the wage rate were below the market value of the output of a particular skill, it would pay individual employers to attempt to hire more people of that skill which would in turn bid the wage rate up. Conversely, if the wage rate were above the market value of the output of the skill, it would pay employers to lay off this skill; these laid-off individuals would be willing to work for less and the wage rate would be bid down. At the equilibrium point (the regional cost of this skill), the wage rate would equal the market value of the marginal worker; there would be neither excess supply (unemployment) nor excess demand (rationing) of this skill.

In actuality, we very rarely have pure competition in labor markets. Monopoly power exists on both the employer and employee sides. Often in any particular area there are

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*Once again we are seeing our technical definition of the word "competition" - neither buyer nor seller can influence price.

only one or two employers requiring a particular skill. Employer monopolies can, and historically have, forced wages down to subsistence levels, well below the regional cost of labor. Employees have responded by forming unions generating countervailing monopoly power. The resulting collective bargaining does not meet our definition of competition. In addition, legal limitations on wages and working conditions, professional and licensing requirements, and racial and cultural biases place further contraints on labor market competition. Often the result is that the market wage rate for a particular skill is higher than that which would occur under competition, higher than the regional cost of labor. The amount of labor demanded at this higher wage will be less than the supply. Some labor will be unemployed.

To the extent that this is the case, our earlier analyses will underestimate the increase in regional income associated with certain of the potential developments, for these analyses do not account for the increase in income of regional employees who find themselves making more money as a result of the development. To put it another way, if there is unemployment, in using market wage rates for regional labor costs in our earlier analyses we have overestimated the cost to the region of the projects. Our purpose in this chapter is to estimate the magnitude of this overestimation and correct for it.

I.5.2 Difficulties associated with estimating the regional cost of labor

There are two basic methods by which economists attempt to estimate the regional cost of labor in the face of unemployment. In developing countries, where the basic structure of the economy is relatively simple, they develop quantitative models which take explicit cognizance of the basic resource constraints facing the society - the fact that at any one time the society has just so much capital and just so many man-hours of each skill available to it. With such a model, the economist then calculates the maximum market value of the society's output (real regional income) which can be obtained given these constraints. He will then pick one of the labor categories, reduce the amount of this skill available by, say, 10,000 man-hours, and repeat the calculation for maximum regional income. The difference between the first and second computation divided by 10,000 is an estimate of the regional cost of this type of labor per man-hour, for it is the loss in regional income associated with the loss of a man-hour of this skill.* He has used our basic definition of cost to estimate the regional cost of this category of labor.

In developed regions, the structure of the economy is usually too complicated to allow one to develop a model which will usefully predict the change in regional product associated with a change in the amount of a particular labor skill available. Thus, one is left with attempting to estimate for a particular skill, how far its wage rate would drop, if at all, if all the constraints on competition were removed. A

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*Interestingly enough, these computations generally indicate that the regional cost of labor is higher than expected even in societies where supposedly everybody is lying around with nothing to do. This is backed up by fragmentary experience with large projects (roads, dams) in developing countries. Such projects siphon labor off the farms. The result, where examined, invariably has been a decrease in agricultural output, indicating that this labor is certainly not costless.

literature search by the study group together with conversations with a number of economists working in the area of unemployment revealed that surprisingly little work in this area has been attempted.

The reason is that the answer is critically dependent on the particular skill demanded and the exact structure of the unemployment in the locale of the development. One can have a great deal of unemployment in a particular area, undertake a large project in that area, and still have little effect on unemployment if the unemployed skills do not match the skills required. The rapid development of the ski industry in northern New England has had little effect on the unemployment resulting from the outmigration of the shoe and textile industries.

Further and more importantly from a practical point of view, often the same reasons that caused the wage rate to be higher than regional cost in the first place, prevent the increased demand on labor resulting from the project to affect unemployment at all, regardless of the skills of the unemployed. This would occur, for example, if the labor is supplied by a fully employed union which is strong enough to prevent enlargement of the union to meet the labor requirements of the project. In this case, the demand for this skill due to the project will generally result in an increase in wage rate for the union members but no decrease in unemployment and no net increase in the output of this union. In this situation, the increase in income of the union members will be matched by some combination of a decrease in the public or private profits of the project or an increase in final market prices (decrease in real income of consumers). There will be no net increase in national income due to the wage rise. There will be an increase in regional income only to the extent that the employers and consumers are extraregional.* When the self-interest of the union's members is coupled with cultural or racial biases, this result becomes the rule rather than the exception. Large increases in construction investment in New York City in the sixties had little or no impact on unemployment despite the fact that many of the skills required were relatively low-level or easily taught. They did result in rapid escalation of construction worker wages.

For all these reasons, economists demand that each project in each locale be examined on a case-by-case basis, taking account of the actual structure of employment in that area before one can estimate the net increase in real regional income associated with a new payroll. Given the constraints on this study, we have not undertaken such a detailed analysis for the various payrolls associated with the hypothetical developments. However, we can point out the salient factors involved in such analysis and make some preliminary estimates.

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*For those hypothetical developments for which the great bulk of public and private profits will accrue to entities outside the region and for which an increase in investor cost will not increase the cost of marginal crude, an increase in regional wage rates as a result of the project will be a net increase in regional income. For example, an increase in exploration and production wages of Georges Bank oil, which is completely controlled by the federal government, would be borne almost entirely by non-New Englanders.

I.5.3 Direct impact of regional refineries on employment

The output of the analyses of Chapter I-2 includes our estimate of the increase in oil industry regional payrolls associated with the various alternatives. From the following table, it is clear that by far the largest increase in oil-related payrolls is associated with the regional refineries.

TABLE I.5.1

PRESENT VALUE OF VARIOUS REGIONAL PAYROLLS
(Millions of Dollars)

Consumption Growth Rate	2%		4%	
Reg. Cost of Capital	8%	15%	8%	15%
Refinery Construction	147	254	394	202
Refinery Operation	297	891	1,113	371
Refinery Total	444	1,145	1,507	573
Large Find*	47	27	47	27

With respect to the refinery, the first question we must ask is what portion of the refinery's labor could be supplied by relatively low-skill New Englanders. Various industry sources indicate that white collar jobs (administration, accounting, clerical, medical, lab services and engineering) account for about 25% of the number of jobs in a simple fuel refinery. Of this number, perhaps 11% are secretaries and clerks, which jobs pay about 80% of the refinery average. The actual control and monitoring of the processing equipment requires another 25% of the refinery's work force. The key person in process control is the operator. The operator is the person in charge of a particular process unit for a shift.

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*Ten billion barrels oil inplace, 1000:1 gas/oil ratio, 10 fields. This find has the largest labor requirements of all the discoveries investigated in Chapter I.2.

He functions as a foreman and is paid about 20% in excess of the average refinery rate. The average operator is supported by approximately six assistants and helpers.

Something over 40% of the work force is involved in maintenance. About 15% of the payroll of this force is at top skill level (Chief Electrician, Chief Machinist). The remainder of the work force handles various jobs such as protection, shipping room, etc.

If we assume that all jobs down to and including the operator - top technician level will be handled by extraregional immigrants or by New Englanders whose skills guarantee that they would be employed in the absence of a refinery, something over 60% of the payroll remains. About 1/5 of this remainder are low-level white collar jobs; the rest, blue collar workers. With this as background, we will operate under the assumption that 60% of the payroll could be handled by relatively low-skill New Englanders. About 80% of these jobs would be restricted to younger males. The assumption of these jobs by New Englanders would require an explicit training program. The oil industry reports that the ordinary refinery operates with 23% trainees and 77% experienced workers. (Forsgren, 1971). Thus, it would be impossible to start up a refinery with simply experienced operators and raw trainees. However, there is little reason to believe that such a training program would not be undertaken, perhaps with some urging. The refinery will be a net addition to American refinery capacity. Thus, new workers will have to be trained somewhere and relocation expense and local pressures point to training local people.

This is consistent with foreign grassroots refinery experience. Generally, only management and top skills are imported. For example, at a recently built petrochemical complex in Puerto Rico, 1470 of the 1500 person initial labor force are Puerto Rican. General laborers have had little difficulty taking on most refinery jobs in Wales and Norway. A major complaint of fishing boat owners in Southwest Wales, where a number of refineries have recently been established, is that the refineries have bid away their crews. Under the assumption that 60% of the payroll would go to relatively low skilled New Englanders, we will examine the labor surplus in the two hypothesized regional refineries' locations.

Now some of this low skilled labor may be attracted from a considerable distance. However, we regard it as extremely unlikely that a significant portion of the low skilled labor will be supplied by immigration from outside the six state region. The regional pool of unemployed, 380,000, is far higher than the refineries' requirements, even when one realizes the bulk of this pool is immobile and a large part close to unemployable. Immigration of low-skilled labor from outside the region would involve movement from generally lower unemployment areas to higher unemployment areas, and from better weather to worse weather. However, there may be considerable relocation of regional labor within the region. In fact, for the Machiasport location, this is almost inevitable.

I.5.3.1 The Machiasport location

Washington County, which composes the entire eastern corner of Maine, is often cited as a pocket of unemployment. For the last three years, the average annual unemployment rate has been running at 11½ percent. However, this unemployment is highly seasonal. In the winter of 71-72, it stood at 15%; in the summer of 72, at 6.5%, out of a workforce of 10,300. That is, the summer unemployed within commuting distance of Machiasport is about 650 people. The breakdown of these unemployed is interesting. Forty-two percent have not graduated from high school. 62% are female. The age breakdown of the males is

Less than 22	8%
22-35	35%
35-45	22%
45-55	15%
55-65	12%
Greater than 65	8%

Thus, during the winter, there are about 390 males under 45 employed in the County; during the summer, about 160.

Our analyses assume that a regional refinery will be large enough to handle all of New England's non-residual consumption. This implies the establishment of a one and a half million barrel per day refinery in 1978 with periodic additions after this. Such a refinery will have an initial work force of about 4000 people plus construction crews. It is obvious that the great bulk of the labor required for such a refinery in the Machiasport area will be met by some combination of:

a) reduction of locals working at other jobs
b) reduction of outmigration from the county
c) in migration from outside the county

The regional cost of labor in all three of these categories is far from zero: category (a) 's regional cost being approximately what they are being paid now; category (b) 's regional cost being what they would have been paid elsewhere; category (c)'s regional cost being what they were paid elsewhere which, given the mobility they exhibit by immigrating, will be somewhere near the overall regional value for their skill level.

The Machiasport refinery labor will not be costless from the regional point of view. On the other hand, the regional cost of at least the lower skill levels is undoubtedly less than what we have assumed they will be paid in our Chapter I-2 computations. In that chapter, refinery labor was costed at an average wage of $8900, which is the prevailing (1971) East Coast average. The average earnings of male, unskilled, non-farm labor in Washington County in 1970 was only $4067. For the entire state of Maine, this figure is still only about $4700. Assuming these people will be paid at 85% the average refinery wage (about the level for below operator skills) and adjusting for inflation, these people will be making about $3000 a year more with the refinery than they would without it.*

In summary, for the Machiasport location, we believe a preliminary estimate of the direct increase in regional income due to the refinery payroll would be .6 x .33 or 20% of the gross value of the payroll. The resulting present value equivalents are given in the following table.

Preliminary Estimate of Direct Increase in Regional Income Due to Machiasport Refinery Payroll Millions Of Dollars

	Growth Rate	
Cost of Capital	2%	4%
8%	230	310
15%	90	120

From this increase must be deducted any decreases in income to landowners, tourist business, and fishermen which result from the external effects of the refinery: pollution and scenic values. Estimation of this effect is addressed in Chapter I-8.**

I.5.3.2 The Dighton location

The southeastern New England location can be tackled in a similar manner. In September 1972, the total number of unemployed in Taunton, Fall River and New Bedford was 9,350. Of this number, approximately 35% are males under 45. Education appears to be a real problem in this area: in New Bedford

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*Even if the locals don't actually get paid the national levels, this difference is an increase in regional income if the products markets are sufficiently competitive so that the savings is passed on to the regional customer.

**It would be incorrect to deduct losses due to lost employees who are now working on the refinery. We have already accounted for this loss in costing the labor at what it's presently earning.

32% of the unemployed have less than 8 years of schooling. In Bristol County, 47% of the male labor force have not completed high school. A significant percentage of the unemployed are Portuguese and Cape Verdean immigrants. However, exact data is lacking on the cultural background of the unemployed.

The 1970 skill (last job) breakdown of the unemployed males by city is:

	Fall River	New Bedford	Taunton
Professional	46	79	17
Sales/clerical	108	110	5
Craftsmen	404	303	98
Operatives	393	407	176
Labor - non-farm	410	354	99
Labor - farm	14	25	9
Service	88	118	36
	1,463	1,396	440

Under the possibly false assumption that all the males under 45 (57%) are sufficiently well-educated to be trained for lower level refinery jobs, it appears that there is presently sufficient labor surplus in Bristol County to supply the bulk of the refinery's regional labor requirements. Assuming no other opportunities exist <u>or develop</u>, the regional cost of this labor is close to zero. Whether the labor would actually be drawn from this surplus depends on: (1) the actual capability of the unemployed to absorb training, (2) the extent of retraining undertaken, (3) the willingness of the relevant labor unions to broaden their ranks, (4) the strength of biases against Portuguese extraction.

As argued earlier, our best guess is that these unemployed could handle about 60% of the payroll. Assuming aggressive retraining, intensive use of regional labor, <u>and that presently</u>

<u>unemployed would remain unemployed in the absence of a refinery</u>, the regional cost of refining labor for the Dighton plant may be as low as 40% of the cost we used in Chapter I-2. That is, 60% of the refinery payroll would be a net increase in regional income. We regard this as an extreme. We can be sure that at least some of the presently unemployed labor which will take these jobs will find other employment some time in the future, if not within the region than outside it. We can be sure that the refinery will attract applicants for jobs from a sizeable portion of the region and that the refinery will actually employ the more easily trained, higher skilled fraction of these applicants--precisely the people most likely to find employment in the future elsewhere. However, on the basis of the analyses we have performed, it is impossible to say how much lower than 60% the actual net increase due to the payroll will be. Therefore, in our summary studies in Chapter I.8, we will display the results of three assumptions concerning payroll effects

1) No effect: full employment
2) Direct effect = 20% of Payroll
3) Direct effect = 60% of Payroll

The second assumption being based on our preliminary estimate for Machiasport and the last an extreme estimate for Dighton.

We shall see that some of these numbers are not small compared with some of the other changes in regional income with which we have been dealing. They can be as high, for the extreme assumption, as the swings in national cost associated with moving from a deep-draft Delaware port to a New England refinery. They are small compared to swings in regional income associated with swings in foreign crude price, the import quota, or control over a large Georges Bank discovery. The point is that they are large enough to merit considerably more detailed attention than we have given them in this study. Any refinery proposal should include a detailed breakdown of the sources from which the refinery's work force will be drawn, the retraining plans which would be used, and the resulting sets of skills.

I.5.4 The impact of the other payrolls

As pointed out in I.5.3, the other payrolls associated with the various developments are quite small compared to the refineries. In general, they are down by a factor of 10 or more. Therefore, it is not too important what we assume about these expenditures with respect to the difference in wages and regional costs. Nonetheless, they do merit some attention.

The second largest set of payrolls associated with the various hypothesessinvolve the offshore oil developments themselves. As indicated in Table I.5.1, the present value of these payrolls is always less than forty million dollars. These figures do not include the crew of the pipe-laying barges, 50% of the operating payroll, and 25% of the platform construction labor. Other assumptions are, of course, possible, but it really doesn't make too much difference since the total payrolls are small compared with other numbers with which we will be dealing.*

In general, the same phenomena which tend to make the net effect on regional income of the refinery payroll a fraction of the payroll itself also apply to the offshore payrolls; but with more force. Much of the offshore labor is specialized contractor personnel (exploration crews, drilling contractors, mud contractors, completion specialists, etc.) who will be on site for at most a very few number of years. Unless the Bank promises to be a province of continuing drilling activity, it will not pay to train regionals for these jobs. The middle and lower level long-run operating and maintenance personnel may well be drawn from the region. By nature, these people will be young, mobile males. While these people will likely make more on the platforms (∿ $14,000 per year) than they would

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*Our simulations assume no workover and no secondary recovery. To the extent this occurs, our analyses are conservative, both with respect to the find's effect on regional income directly and through offshore employment.

otherwise, they will certainly have other employment opportunities.

In Chapter I.8, the same set of assumptions which we have made about the direct effect of refineries' payroll are used with respect to regional offshore payroll, i.e. three cases: 0, 20, and 60% of gross regional payrolls. We feel this may be biased in favor of the offshore development, but the payrolls involved are so small, relatively speaking, that any such bias is unimportant.

The other payrolls associated with our developments (pipeline construction), terminal personnel, etc. are another factor of ten smaller than the offshore payrolls. Besides, these payrolls are undoubtedly matched by decreases in payrolls to labor employed in the present products distribution system. Thus, they have been ignored in our summary computations in Chapter I.8.

I.5.5 Shoreside construction and support facilities

There is some chance that regional shipyards might successfully compete for the jacket construction contracts. The cost of transporting a $3-4 million jacket from the Gulf Coast to the Bank may be as high as $200,000. Whether or not this savings is sufficient to make up for the edge the Gulf Coast yards have in relevant experience and productivity has not been examined. At best, the local yards are unlikely to make any large profits on successful bids. Besides, the yards are largely extraregionally owned. Thus, any net effect on regional income will have to come through shipyard labor which would be employed on these contracts and unemployed otherwise. Since even for a large discovery with a large number of fields, the total value of these contracts will be in the neighborhood of $70 million, according to Chapter I.2, about 25% of which value will be payroll, and a fraction of this payroll will be a net increase in regional income, we do not foresee this effect being significant compared to the other swings in regional income identified in Chapter I.8.

Phillips' shoreside facilities supporting the Ekofisk area, a multi-billion barrel discovery, employ about 25 people, 4 or 5 of whom are imported. Humble employs about 60 people shoreside in direct support of their Gulf facilities. In our estimation, the effect of the direct support facilities on regional income will not be significant.

I.5.6 The impact of the respending of the various increases in regional income

The bulk of the regional oil-related payrolls will be spent within the region. For that matter, the same thing is true of any increase in regional income, whether it be the result of a lowering of prices or of an increase in regional public or private profits. This respending will generate additional revenues and employment in certain service activities. Insofar as these additional revenues are not matched by an increase in regional costs and this additional employment is drawn from formerly unemployed, there will be a net increase in regional income associated with the activity so generated.

However, there are a number of important factors which tend to make these respending effects small on net.

1) A goodly portion of this respending will be on goods in which the regional input is only a small proportion of the total value. Thus, even if there is regional overcapacity or unemployment in these sectors, this respending had little effect on regional income. Automobiles are a prime example of this category.

2) A goodly portion of this respending will be on goods in which there is little overall regional overcapacity unemployment. In these goods, the revenues associated with the respending will be closely matched by the cost to the region of supplying the good. A wide range of goods fall in this category, running from road and building construction to movies.

3) A goodly portion of this respending will be on goods in which the supply is rather insensitive to price - goods in which there is only so much to go around. Land is the prime example. For such a good, the additional spending will not elicit an additional supply but rather an increase in price. An increase in price of a good, say, land, does not in general represent an increase

in regional income. It is an increase in extra-regional income only if the buyer is extra-regional. Otherwise this price change is a wash, for what the regional seller gains in real income from the price increase, the regional buyer loses.

4) A certain portion of the respending will be on goods in which the regional cost of providing the service is actually in excess of the additional revenues. Certain public recreational facilities, certain transportation and utilities services, and sometimes education may fall into this category. For such goods the increase in demand must be met by a regressive increase in price or an increase in congestion. In the latter case, the increase in regional cost associated with meeting these additional demands will be greater than the additional revenues, in which case there will be a net loss in regional income associated with the respending.

In summary, with respect to respending, net increases in regional income will be concentrated almost entirely in those markets where the additional demands will generate additional supply with little increase in price and in which low-skill regional labor content is high. We have attempted no quantitative analysis of such markets, but it is clear that such markets are very much in the minority and increasingly so. The net effect on regional income of the portion of the respending actually spent in these markets will be a fraction of these expenditures. At best the net effect of first-round respending is a fraction of a fraction of the direct net increases in regional income. As noted in Chapter I-1, second-round respending is a fraction of this fraction and the effect very quickly dies out as number of rounds of respending increases.

On this basis, we have not adjusted the overall changes in regional income derived in Chapter I.8 to account for changes in regional income. The overall effect of this procedure to bias our results (very slightly, we believe) against those hypothetical developments with large, direct increases in regional income. In this regard, it is important to keep in mind that this bias applies to all the increases in regional income, not just those associated with changes in regional petroleum payrolls. Thus, this omission will have no effect on the relative rankings of the hypotheses.*

*This is not completely true. Direct payments to immigrants brought into the region (which are not increases in regional income by our definition) will generate respending. Thus, this procedure is slightly biased against the options with the higher immigration. However, payments to immigrants are, in any case, quite small compared with the other numbers with which we will be dealing and only a fraction of a fraction of these payments will translate into a net increase in regional income.

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Maine Occupational 1970 Wage Survey. Maine Department of Labor and Industry, DLI Bulletin No. 476, March, 1971.

Results of 1970 Census Survey. U.S. Bureau of Census, Series C Maine and Massachusetts.

Latest unemployment figures and breakdown based on conversations with various members of Maine Employment Security Commission and Massachusetts Division of Employment Security.

Chapter I.6
Impact on Regional Income of the Georges Bank Fishery - Georges Bank Petroleum Conflict

I.6.1 Introduction

The purpose of this chapter is to investigate the impact of offshore petroleum developments on the Georges Bank fishing industry and the resultant effect on regional income. This chapter depends heavily on Chapters I.1, II.1, II.2, and II.5. Our procedure will be to first describe the structure of the Georges Bank fishing industry, to then examine the effect of physical interference, and finally to examine the effect on regional income of the offshore spills and discharges.

I.6.2 Overview of the domestic fishery

The best data available concerning the fisheries resource distribution across the Georges Bank comes from the reports which are given by domestic fishing boats when they land their catches. For example, as part of the study effort, a member of the M.I.T. staff served as a crew member aboard a Boston stern trawler for a trip. The trip observed covered an eleven-day period, during which the boat fished the northern edge of Georges Bank and made a day-and-a-half trip to Browns Bank. The trip resulted in a mixed catch of haddock, cod, pollock, and halibut. On this particular boat after each trip the mate meets with a representative of the National Marine Fisheries Service and reports on the amount by species and location of his catch. The part of the report that we are interested in shows the total weight of all species which are landed on that trip and one point of latitude and longitude which for statistical purposes is the assumed catch location for all the fish landed from that trip. To the extent that the boat didn't trawl again and again over that same point, considerable resolution is being lost. This will also tend to bias the results toward the high productivity squares since the reports will tend to indicate that all the catch comes from these squares. But, to be practical, these reports are based on the fishermen's goodwill and any other system would require considerably more effort and might considerably reduce the degree of cooperation now experienced. In any event, this is the best data available.

The N.M.F.S. representative files this catch data based on a system of chart "squares" which are 10 minutes (10 nautical miles) of latitude tall and 10 minutes (approximately 8.3 nautical miles) of longitude wide. For the purposes of this study we have extracted this data for the 150 rectangles which are part of or within the 50 fathom contour of the Bank for the most recent two-year period (1969 and 1970) for which it is available from the N.M.F.S. The area covered is indicated by the gray portion of Figure I.6.1, which also shows the code number for each square.

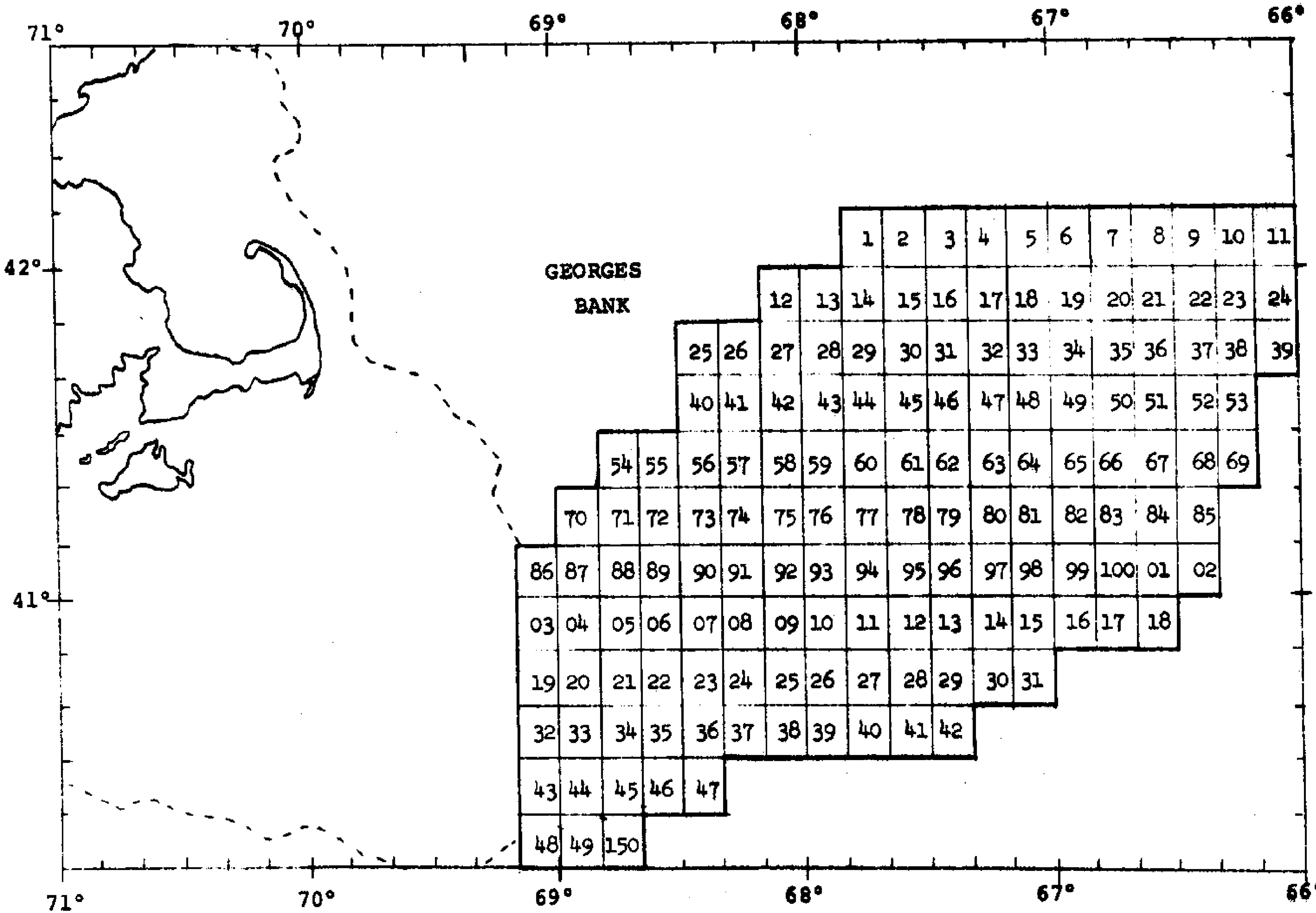

Figure I.6.1 Area covered by NMFS Catch Data and Coding of Grid Squares

Table I.6.1 gives the dollar value of the domestic catch ex vessel for 1969 and 1970 for each grid by port. These figures were obtained by combining the average of the 1969-1970 prices by years with the vessel reports. The table also indicates the total reported fishing effort by grid for this period.

Reporting problems notwithstanding, it is clear that there is a striking variation in catch value across the Bank. Grid values range from over a million dollars to less than ten thousand for the two-year period. As Figure I.6.2 indicates, the high-value squares are clustered on the north-east corner of the Bank in 25 to 40 fathoms of water. There is also a smaller cluster of activity on the southwest end. The northeast cluster jibes rather well with the gravelly, high productivity spawning grounds as outlined in Chapter II-4 and the southwestern efforts match quite closely the distribution of bottom biomass, also described in Chapter II-4.

The breakdown of the catch by port and major species in hundreds of pounds is:

	Boston		Gloucester		New Bedford	
	1969	1970	1969	1970	1969	1970
Cod	64,813	21,878	3,630	4,335	44,057	43,958
Yellowtail	11,523	4,943	3,145	770	469,200	291,830
Haddock	87,209	107,124	25,999	5,469	43,282	34,712
Scallops					22,969	20,287

There is considerable species specialization by port with New Bedford boats dominating the totals; New Bedford accounts for over 80% of the domestic yield of the Bank by value.

TABLE I-6-1

DOLLAR VALUE OF REPORTED LANDINGS BY GRID SQUARE
AND PORT FOR JAN '69-DEC '70
GEORGES BANK

Grid	Days Fishing Effort	Boston	Gloucester	New Bedford	Total
1	1.5	2,143			2,143
2	13.1		23,180		23,180
3	14.4	11,860	2,956	8,028	22,844
4	33.6	36,848	15,415	4,421	56,684
5	103.5	18,407	4,890	130,285	153,582
6	71.3	69,960	3,400	28,836	102,196
7	25.9	77,369		6,563	83,932
8	40.4	51,034	13,959		64,993
9	29.5	38,561			38,561
10	15.0	18,943			18,943
11	2.0	6,317			6,317
12	21.5		74,847 (2)	26,057	100,904
13	127.4	45,063	32,309 (9)	7,480	84,852
14	47.2	30,610	4,438	53,268	88,316
15	31.5			57,340	57,340
16	58.2	38,924	22,481	67,003	128,408
17	74.0	89,780		38,023	127,803
18	84.1	45,510		88,935	134,445
19	151.4	121,559 (8)	1,838	140,998	264,395
20	78.7	1,498	23,450	84,137	109,085
21	52.4		46,977 (6)	30,052	77,029
22	22.6	21,588	10,942		32,530
23	14.9	5,669		13,636	19,305
24	28.1			39,874	34,874
25	41.7	52,930	20,803		73,733
26	137.5	163,816 (6)	76,175 (1)	9,602	249,593
27	115.8	43,308	59,233 (5)	105,919	208,460
28	115.9	61,690	14,329	142,366	218,385
29	54.6	24,775		79,501	104,276
30	61.6	58,908	12,375	21,499	92,782
31	162.0	192,211 (4)	20,628	56,071	268,910
32	267.6	279,951 (2)	22,155	191,390	493,496
33	468.3	115,460 (9)		656,403 (7)	771,863 (7)
34	439.8	216,993 (3)	6,635	427,943	651,571 (10)
35	375.3	36,257	24,319	449,465 (10)	560,041
36	51.6	10,663	1,838	68,923	81,424
37	123.4	15,031	8,351	116,545	139,927
38	232.2			345,485	345,485
39	65.1			119,609	119,609
40	129.4	62,895	10,171	100,906	173,972
41	109.6	114,522 (10)	417	68,542	183,481
42	41.4	38,112	3,636	36,579	78,327
43	76.2	83,906		51,510	135,416
44	25.8	34,160		29,921	64,081
45	50.0	79,505	18,212	19,940	117,657

TABLE I.6.1
(cont.)

Grid	Days Fishing Effort	Boston	Gloucester	New Bedford	Total
46	9417	95,985	14,875	54,846	165,706
47	422.4	187,566 (5)	16,351	498,275	702,192
48	629.4	16,785	26,410	867,201 (2)	910,396 (3)
49	715.6	56,675	72,570 (3)	746,180 (4)	875,425 (5)
50	1170.6	9,290	2,353	1,317,790 (1)	1,329,433 (1)
51	606.3	37,496	14,388	693,296 (6)	745,180 (8)
52	121.9		16,533	165,496	182,029
53	16.0			21,759	21,759
54	39.0	16,659	17,326	19,939	53,924
55	107.0	75,576	20,121	52,457	148,154
56	151.5	68,715	460	130,355	199,530
57	40.8	34,937		24,922	59,859
58	20.7			39,206	39,206
59	28.5	12,731		39,058	51,789
60	4.4		9,590		9,590
61	20.5	32,855		2,931	35,786
62	60.0	76,346	1,716	22,061	100,123
63	206.1	602,581 (1)	32,859 (8)	296,308 (8)	931,748 (2)
64	255.3	31,088	26,088	268,356	352,532
65	482.9	13,406	14,529	534,134 (9)	562,069
66	329.8			398,144	398,144
67	142.3		17,739	175,564	193,303
68	35.8			52,614	52,614
69			None Reported		
70	51.3	28,220		27,175	55,395
71	297.6	124,422 (7)	26,961 (10)	261,785	413,168
72	331.8	69,480	15,884	428,757	514,121
73	102.6	70,818		101,372	172,190
74	16.2		9,650	12,774	22,424
75	42.3			75,385	75,385
76	130.0	109,278	16,028	92,285	217,591
77	29.6		15,619	24,452	40,071
78	21.8		20,814	26,913	47,727
79	86.6		16,314	97,645	113,959
80	325.3	35,010	9,029	370,169	414,208
81	272.3			336,556	336,556
82	66.1	17,406		42,682	60,088
83	139.2			610,399 (8)	610,399
84	175.8			217,530	217,530
85	74.5			105.160	105,160
86	75.1	55,375		68,282	123,657
87	99.8	22,011		107,185	129,196
88	562.4	69,511	34,791 (7)	734,317 (5)	838,619 (5)
89	188.5	46,973	65,141 (4)	221,107	333,221
90	19.0	17,512		11,424	28,936
91	1.5			12,282	12,282
92	15.0	3,253		33,254	36,507
93	66.2	48,116	980	67,407	116,503
94	72.0	47,999	1,483	50,206	99,688
95	59.4	2,108	4,545	66,647	73,300

TABLE I.6.1
(cont.)

Grid	Days Fishing Effort	Boston	Gloucester	New Bedford	Total
96	147.9			193,036	193,036
97	149.4			178,055	178,055
98	56.8			75,798	75,798
99	54.7			60,670	60,670
100	138.7			185,449	185,449
101	148.9	1,991		180,597	182,588
102	77.7			85,124	85,124
103	550.3	72,122		807,556 (3)	879,678 (4)
104	180.3	19,526		220,349	239,875
105	235.0	23,352		309,122	332,474
106	105.7	15,786	6,315	131,514	153,615
107	61.3	7,432		57,957	65,389
108	38.0	24,891		21,151	46,042
109	34.6	8,297	19,568	16,728	44,593
110	12.8	14,481		11,663	26,144
111	50.0			61,977	61,977
112	172.0			207,245	207,245
113	101.9			108,314	108,314
114			None Reported		
115	8.0			8,880	8,880
116	56.0			67,226	67,226
117	28.5			31,413	31,413
118	16.0			15,318	15,318
119	77.8			90,848	90,848
120	59.9	2,165		72,857	75,022
121	10.5	1,088		7,218	8,306
122	180.1		488	211,032	211,480
123	321.3	5,953		352,670	358,623
124	404.9		35	487,386	487,421
125	150.2			184,071	084,071
126	70.4			82,819	82,819
127	92.5	5,450		107,138	112,588
128	35.3			39,082	39,082
129	114.5			127,149	127,149
130			None Reported		
131			None Reported		
132	46.4			62,011	62,011
133	37.1			35,168	35,168
134	8.5			9,738	9,738
135	32.7			31,644	31,644
136	156.5			171,530	171,530
137	33.4			46,169	46,169
138	13.4			21,346	21,346
139			None Reported		
140			None Reported		
141	4.0			3,863	3,863
142			None Reported		

TABLE I.6.1
(cont.)

Grid	Days Fishing Effort	Boston	Gloucester	New Bedford	Total
143	175.6			223,422	223,422
144	32.6			38,989	38,989
145			None Reported		
146	8.0			13,286	13,286
147	8.0			12,868	12,868
148	5.0			5,887	5,887
149			None Reported		
150			None Reported		
Port Totals:		4,755,453	1,147,872	20,065,430	25,968,755

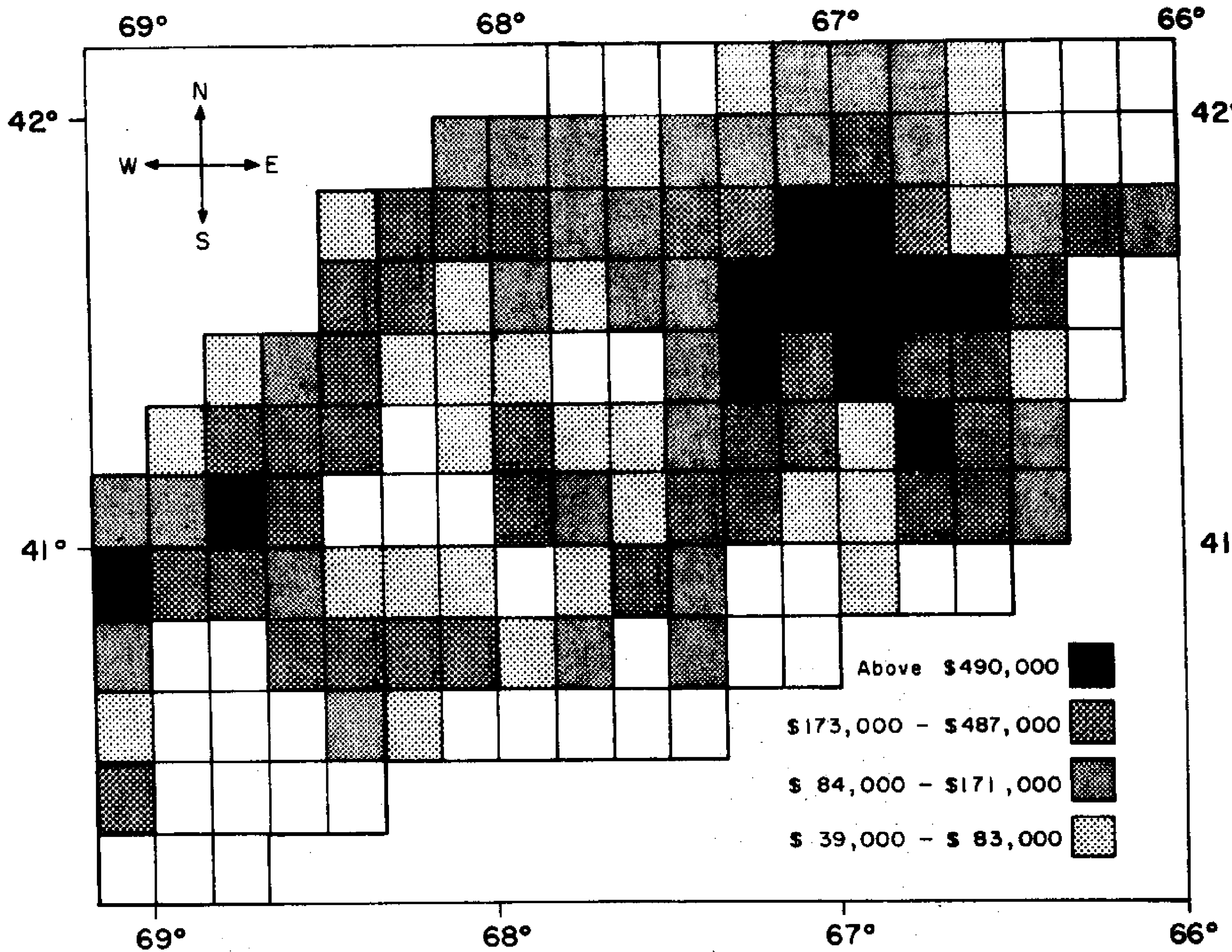

Figure I.6.2 Distribution of 1969-1970 U.S.A. Yield Across Bank.

I.6.3 The domestic Georges Bank fishing fleet*

At present, there are approximately 150 New England trawlers and draggers which work the Georges Bank on at least a part-time basis.

The approximate breakdown by port is:

	New Bedford	Boston	Gloucester
Scallopers	23	-	-
Draggers	117	13	32
Seiners	2	-	-
Stern Trawlers	-	5	-

Only two of the Gloucester boats fish the Bank regularly and there is some question as to the regularity with which the rest of the fleet as a whole works the Bank. Comparing the total take from the Bank, ex vessel (about 13 million dollars) with average crew size and wage data would suggest that, at present, New England is expending 800-1000 man-years per year on the Bank, which would mean that the above vessels, on the average, are spending about 50% of their time on the Bank. Of course, there is considerable variation across the fleet: some of these boats are essentially inactive, some work the Bank on a seasonal or irregular basis and some (the newer, larger boats) spend almost all their time on the Bank. Typically, such boats are 90-120 feet long, and operate with a crew of about 11. The crew works a 10-11 day trip and then has 3 or 4 days off while the boat refits.

The pay on the top boats, which is on a lay or share basis, is reasonably good. According to Charles Martin Associates of Gloucester and New Bedford, the share for a fisherman who works on deck with the nets ranges from about $7,500/year to

*This section does not include the offshore lobster fishery, which will be handled separately in Section I.6.8.

$22,000/year with the average being about $11,000/year. These figures do not vary significantly from port to port. The skipper will make twice as much.

As a check on these figures, records for six large trawlers were obtained. The resulting annual wages per crew member were:

	Max.	Avg.	Min.
1969	15,263	11,842	9,513
1970	16,575	13,331	11,564
1971	17,800	12,725	9,300
1972	16,975	14,003	9,538

One result is that labor accounts for a high proportion of a trawler's expenses. Four 1972 voyage settlement sheets for a modern stern trawler were examined and projected for a 12-month period. Table I.6.2 indicates the resulting breakdown.

Table I.6.2

BREAKDOWN FOR A BOSTON STERN TRAWLER FOR EACH DOLLAR OF GROSS SALES

Crew Wages	53.52¢
Direct wages	
Fisherman's Welfare	
Payroll taxes	
Food	
Boat Expenses	12.32¢
Yearly hauling	
Replacement/maintenance gear	
Outside labor (radar repair, etc.)	
Boat Supplies	10.75¢
Diesel fuel	
Motor oil	
Ice	
Water	
Insurance	6.95¢
Interest on Mortgage	6.05¢
Lumpers (Offloaders)	4.30¢
Boat Owner	3.82¢
Boston Fish Exchange Fees	.50¢
Wharfage Fees	.50¢
Auctioneer at Fish Exchange	.39¢
TOTAL	100.00¢

The share system implies that in this industry, the bulk of profits accrues to labor. If these figures are typical, as we believe them to be, direct labor accounts for some 60% of the input value, durable capital less than 15%. This breakdown will be of interest in our later analysis of the impact on regional income of changes in fishing output.

I.6.4 The foreign fleet

Comparable data on foreign Georges Bank activity is simply not available. However, we do have some data on vessel activity. Table I.6.3 indicates the number of foreign, non Canadian vessels on the Bank over the fiscal year of 1972.* It is clear that the foreign effort is sharply seasonal, peaking in late summer and dropping to nil in the winter, during which time the foreign fleets move south.

There is no available data on the foreign Georges Bank catch.** The closest thing we have is the national fleet reports to the International Conference on Northwest Atlantic Fisheries (ICNAF) for Subarea 5. ICNAF Subarea 5 is indicated on Figure I.6.3. The annual national landings as reported to ICNAF for 1970 and 1971 are shown in Table 1.6.4. With the exception of scallops, the Americans dominate the high-value demersal and benthic species, although they account for only 25% of the reported catch. The foreign catch is concentrated on the lower-value pelagic species, which are generally one step lower in trophic level. On the American market, these fish are worth 1/5 to 1/10 as much as the high-value species. They also, of course, are an important food source for the high-value species. In short, it is unlikely that the non-North American catch in Subarea 5 during this period had an American market value greater than the North American catch. It is probably somewhere in the neighborhood of 15 million dollars.

We have no direct data on the amount of this catch which was taken on the Bank itself. However, an estimate can be arrived at by noting that the Russian fleet in the period

*The N.M.F.S. does not keep track of Canadian activity. The motives for this omission are not at all clear; the results of this omission for analytical purposes are disastrous.

**The Office of Surveillance of the National Marine Fisheries Service at Gloucester has indicated that it does have data on foreign Georges Bank catches but both the method and the results are "classified."

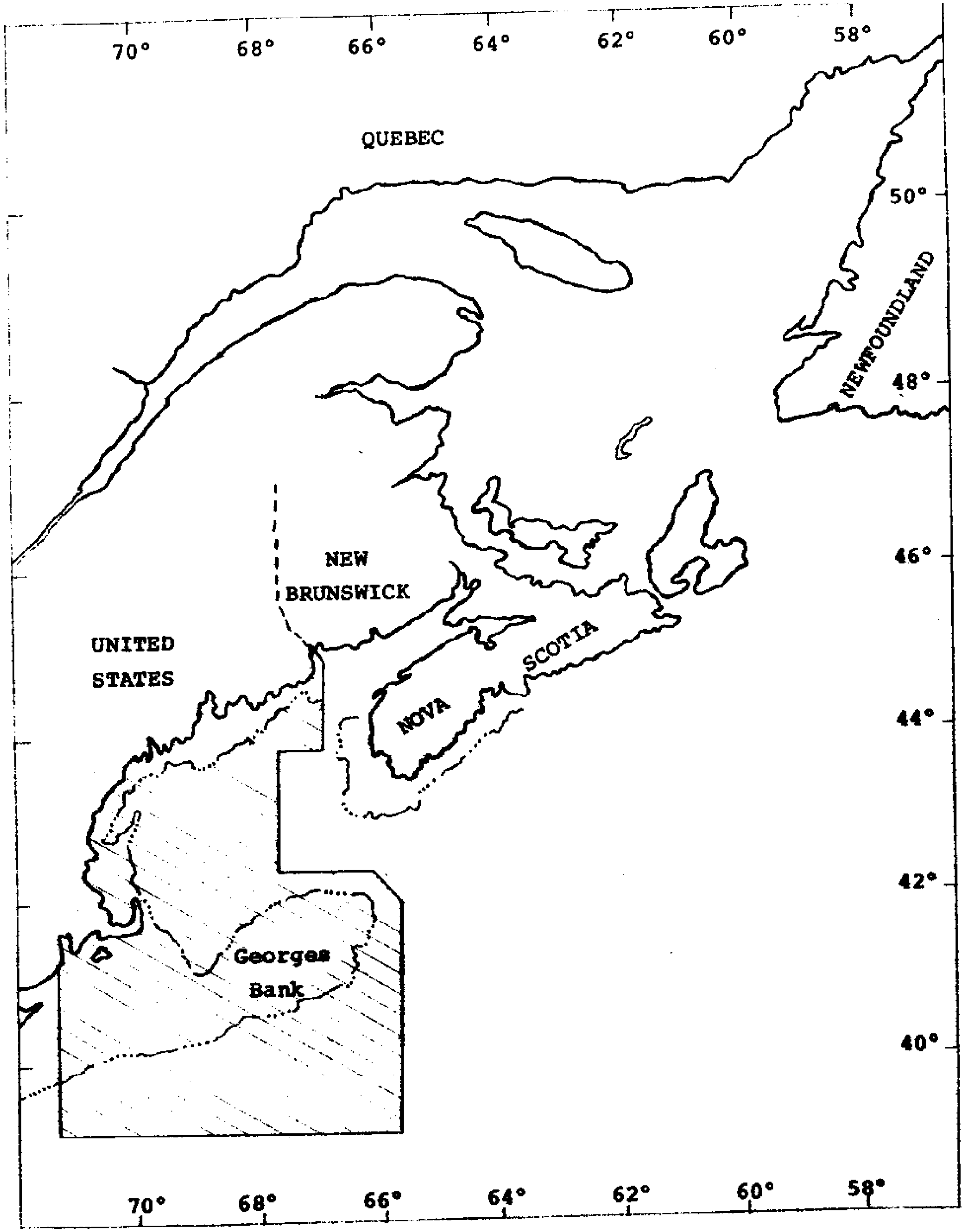

Figure I.6.3 ICNAF Subarea 5 (Hatched Area).

	1971						1972					
	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Soviet	45	80	65	64	4				60	25		94
Polish	18	47	74	60	35							9
E. German	11	8	23		5							4
W. German	4	10	19	11								2
Bulgarian		3	4	4								
Rumanian		2	1	2								
Greek	1	1										
Spanish	2	12	30	12								2
Japanese		3	4	5								5
Norwegian												
Cuban												1
TOTAL	71	160	220	158	44				60	25		117

Table I.6.3

Number of Foreign Vessels On or Inside 100 Fathom Circle, Georges Bank

(Does not include Canadian boats)

Table I.6.4
Subarea 5 - Landings by Species for 1971 and (1970) - Metric Tons

Species	USA	Canada	Japan	Poland	Romania	Spain	West Germany	USSR	Non-m[1]	Total
Cod	22983	3098	20	155	-	7619	4	1270	-	35149
	(22347)	(2609)	(15)	(641)	(129)	(7249)	(14)	(364)	(4655)	(38023)
Haddock	8486	1715	10	-	289	1337	4	374	-	12215
	(9872)	(2016)	(1)	(15)	(-)	(845)	(-)	(103)	(-)	(12852)
Redfish	16262	269	4	84	41	-	-	3394	1	20055
	(15534)	(338)	(19)	(30)	(35)	(-)	(2)	(-)	(115)	(16073)
Silver Hake	13325	-	103	-	-	-	-	81515	-	94943
	(19379)	(-)	(74)	(15)	(113)	(-)	(-)	(28997)	(439)	(49017)
Red Hake	2783	-	7	-	-	-	-	25353	97	28240
	(4281)	(-)	(-)	(-)	(-)	(-)	(-)	(6515)	(197)	(10993)
Herring	33884	28000	2434	69086	586	-	56467	63903	17426	271786
	(30484)	(5012)	(1223)	(54875)	(685)	(-)	(88221)	(39173)	(39268)	(258941)
Mackerel	1405	-	272	43684	912	3	1175	59074	7090	1136[illegible]
	(3092)	(-)	(463)	(40987)	(758)	(-)	(1004)	(56457)	(9006)	(111767)
Yt. Flounder	22312	105	3	-	33	-	-	925	-	23378
	(31920)	(75)	(-)	(-)	(-)	(-)	(-)	(2905)	(-)	(24900)
W. Flounder	10387	62	-	-	-	-	-	1946	-	12395
	(11697)	(61)	(-)	(-)	(-)	(-)	(-)	(462)	(-)	(12220)
Amer. Plaice	2168)	40)	2	-	-	-	-	340	-	2550
	(2586)	(87)	(-)	(-)	(688)	(-)	(-)	(945)	(-)	(4306)
Witch	3156	31	-	-	-	-	-	2713)	-	5900
	(2959)	(15)	(-)	(-)	(-)	(-)	(-)	(108)	(-)	(3082)
Oth. Flounders	150	16	4	15	118	-	-	843	-	114[illegible]
	(307)	(19)	(119)	(8)	(107)	(-)	(-)	(-)	(87)	(647)
Cusk	776	1040	-	-	-	-	-	-	-	1816
	(552)	(813)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(1365)
Ocean Pout	2678	-	-	-	-	-	-	3553	-	6231
	(5851)	(-)	(-)	(-)	(-)	(-)	(-)	(895)	(-)	(6746)
Pollock	4724	1636	5	-	-	183	633	1163	5963	14307
	(3592)	(853)	(1)	(-)	(-)	(6)	(3156)	(51)	(-)	(7659)
Angler	88	-	-	-	-	5	-	3644	-	3737
	(201)	(-)	(-)	(-)	(-)	(-)	(-)	(477)	(-)	(678)
Sculpins	863	-	-	-	-	-	-	1095	-	1958
	(2608)	(-)	(-)	(-)	(-)	(-)	(-)	(2230)	(-)	(4838)

Subarea 5 - Landings by Species for 1971 and (1970) - Metric Tons (Continued)

Species	USA	Canada	Japan	Poland	Romania	Spain	West Germany	USSR	Non-m[1]	Total
W. Hake	2663	100	109	-	-	-	-	-	-	2872
	(1845)	(46)	(159)	(-)	(-)	(63)	(-)	(-)	(-)	(2113)
Bluefin Tuna	1044	424	-	-	-	-	1	-	-	1469
	(563)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(563)
Butterfish	419	-	973	-	-	-	-	400	-	1792
	(391)	(-)	(1723)	(-)	(-)	(-)	(-)	(396)	(-)	(2510)
Menhaden	6355	-	-	-	-	-	-	-	-	6355
	(5122)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(5122)
Atl. Saury	-	-	-	-	-	-	-	2144	-	2144
	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(1054)	(-)	(1054)
Alewife	940	-	-	-	-	-	-	9014	2585	12593
	(1463)	(-)	(-)	(-)	(-)	(-)	(-)	(13135)	(75)	(14673)
Argentine	-	-	5398	-	-	-	-	1893	-	7291
	(-)	(-)	(369)	(-)	(-)	(-)	(-)	(999)	(-)	(1368)
Sharks	13	-	64	-	-	-	-	9045	-	9122
	(75)	(-)	(334)	(-)	(-)	(-)	(-)	(4336)	(-)	(4745)
Skates	741	2	-	-	-	-	-	3750	3	4496
	(1437)	(1)	(-)	(-)	(-)	(-)	(-)	(2544)	(14)	(3996)
Oth. finfish	4832	211	1239	10769	114	-	3	8884	545	26597
	(6679)	(1352)	(660)	(5169)	(205)	(-)	(2)	(2965)	(14254)	(31286)
Scallops	14142	32434	-	-	-	-	-	(-)	(-)	46576
	(12938)	(34006)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(46944)
Oth. Shellfish	36157	102	4612	-	-	256	-	6169	-	47296
	(60335)	(-)	(5396)	(-)	(-)	(-)	(-)	(1065)	(-)	(66796)
TOTAL	213736	69285	15259	123793	2093	9403	58287	292404	33710	817970
	(258110)	(47303)	(10556)	(101740)	(2720)	(8163)	(92399)	(166176)	(68110)	(755277)

1 1970 Non-member catches include 4V, 5 and 6 since not reported separately.

July 1971 to June 1972 spent 49,796 ship-days in the N.W. Atlantic region. 30.7% of these or 15,309 were spent on Georges. A guess of 30-40% would be likely to be close.

Given present laws against landing foreign catches in the states, the only way a drop in foreign flag Georges Bank catch could affect New England regional income is by increasing the price of imported fish.* Since the bulk of the non-Canadian catch is in low-value species, not imported in any great quantities and since a drop in Georges Bank take of these species by itself could have little effect on price, it appears that we can make a rather strong statement that a loss in non-North American flag catch due to either structure conflict or a spill would have no measurable effect on New England regional income.

The Canadian situation is quite different, due primarily to the extremely important scallop fishing. In 1957, the Americans had the Georges Bank scallops to themselves. Since that time, the Canadians have progressively increased their share of the yield, until at present they harvest 80% of this very valuable ($1.80 per pound of meat) catch. See Table I.6.5.

Table I.6.5

TRENDS IN THE SCALLOP LANDINGS FROM GEORGES BANK
(ICNAF Division 5Z)

Millions of Pound Meat Weight

Year	Canada	U.S.	Total
1961	10.1	24.5	34.6
1962	12.6	21.3	33.9
1963	13.1	17.5	30.6
1964	13.2	13.9	27.1
1965	10.1	3.3	13.4
1966	10.7	2.0	12.7
1967	11.1	2.7	13.8
1968	10.6	2.3	12.9
1969	9.6	2.5	12.1
1970	8.9	2.5	11.4
1971	8.7	2.5	11.2

*Foreign flag vessels do buy fuel in New England and very occasionally some maintenance. However, as argued elsewhere in the report, the decrease in regional income from selling very slightly less fuel is going to be nil.

At present American prices the Canadian scallop catch is worth about $16 million per year. The Subarea 5 Canadian cod and haddock catch is worth another $4 million. 70% of the Canadian catch is exported to the United States. Thus, it would be "worst" case, but not outrageously, to assume that any loss to the Canadian Georges Bank fishing as a result of petroleum production is transferred to the U.S. consumer via price increases. A goodly but undetermined portion of these U.S. consumers will be New Englanders.

For lack of anything better, we will assume that 50% of the loss to the Canadian Georges Bank fishery will fall on New Englanders. Thus, throughout the remainder of the chapter, the entire 1971 Canadian Subarea 5 catch of haddock, cod and scallops will be valued at U.S. market prices, distributed proportionally among the squares according to the distribution of the 1971 U.S. scallop catch as indicated by Figure I.6.4. 50% of the value will be added to the value of the 1970 American catch by square. Notice that the bulk of scallop fishing is concentrated in the Great South Channel area in water depths of 20 to 40 fathoms.

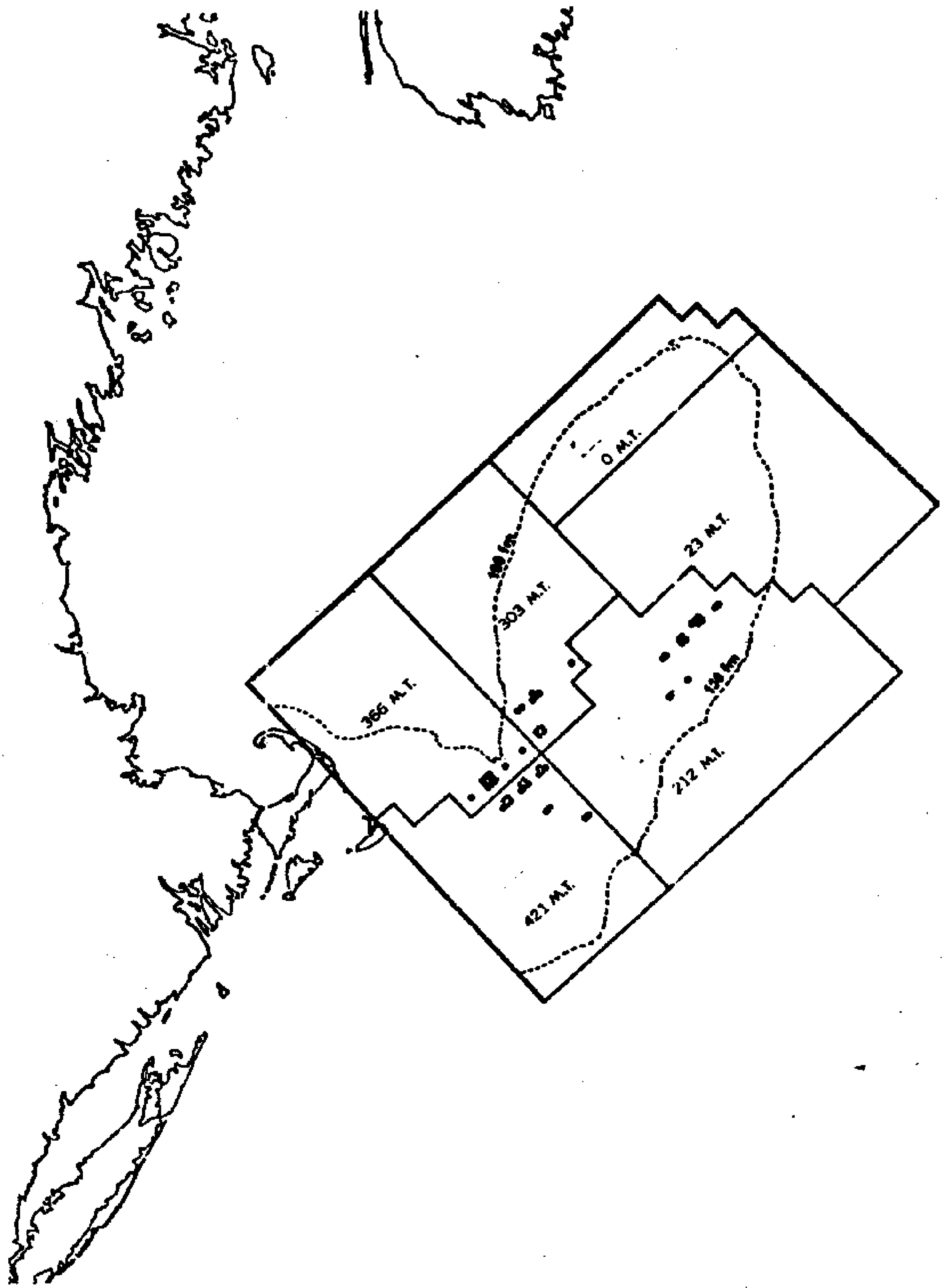

Figure I.6.4 Distribution of 1971 USA Scallop Catch

I.6.5 Impact on regional income of the structures

The analyses of Chapter I.2 indicate that even a very large find on the Bank would be produced from less than 25 independent, unconnected structures.* Discharges aside, there are several possible categories of conflicts or interrelationships which these structures could have with the fisheries. They are:

1) Navigational hazard or aid.
2) Provision of additional hard surface area and shelter for flora and fauna.
3) Interference with trawling due to seabottom obstructions.
4) Interference between trawling and seismic activities.
5) Interference with trawling due to platforms.

I.6.5.1 Navigational hazard or aid

Our on-board observations of the Georges Bank fishery indicate that the fishermen know pretty much exactly where they are at all times. Their productivity depends on it. The fishermen make extensive use of LORAN which, on the Bank, allows them an accuracy of better than a quarter mile. Thus, the structures will add little to the navigational accuracy of the fishermen.

This fact also mitigates against the danger of collision. We have not undertaken any formal, probabilistic analysis of the structure-vessel collision problem. One reason for this omission is the Gulf Coast experience. There are approximately 4000 separate structures in the northern Gulf. About 2000 large (over 65') shrimp trawlers operate in this area. Louisiana Fish and Wild Life officials report that in the last 15 years there have been "three or four" reported collisions between shrimpers and structures. No oil spills were reported as a result of these collisions.

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*Certain of the structures will consist of more than one jacket connected by bridges. Since such platforms will be within 200 yards of each other, for the purposes of this chapter, they will be regarded as a single platform.

While it is impossible to transfer Gulf experience to the Bank directly, it is obvious that the collision incidence experienced in the Gulf would have to be increased many times before one would expect more than one or two collisions throughout the life of even a 25-platform project. As indicated earlier, at any one time, there will be about 70 domestic boats on the Bank. In addition, during the good weather, summer months, there will be some 300 foreign vessels on and in the vicinity of the Bank. However, all but five or six of these vessels will be catchers of less than 500 tons. These vessels ordinarily move at slow speeds, less than eight knots, and their navigational accuracy is good. While a collision at such speeds could severely damage a catcher, it is extremely unlikely to penetrate a platform to well casings or risers.

Thus, even if a major collision occurred, a major spill would be unlikely. Of course, the vessel damage would be a loss to someone - presumably the vessel's insurers. However, the insurers evidently do not consider this factor very important as the insurance rates for the Gulf fleet are considerably lower than those of the Bank fishery. Other factors override the platform issue. Unless insurance premiums rise as a result of the structures, the cost to the regional fishermen due to collisions with structures will be quite small.

With respect to the large factory and resupply ships, a regulation forbidding approaching closer than, say, 10 miles to a platform would cost the foreign fishermen little, since the factory ship need not be in a particular location, while making the chances of a major collision quite small. In short, while we have not analyzed the issue in any detail, it appears difficult to argue that the collision problem will represent a noticeable loss in regional income.

Despite the apparent lack of collisions, fishermen in both the Gulf and the North Sea have complained about poor or missing markers and lights on abandoned or subsidiary structures, such as workboat mooring buoys. Enforcement of marking and lighting regulations for secondary and abandoned structures appears to have been poor. Maintenance of navigational aids will be an area of concern for the body regulating any Georges Bank development.

I.6.5.2 Provision of surface area and shelter

It appears to be an incontestable fact that the structures in the Gulf have greatly facilitated the rapid expansion of the local recreational fishery. This is the unanimous opinion of everybody we talked to in the Gulf: oil company personnel, Fish and Wild Life officials, charterboat men and sportsmen. Productivity in the immediate vicinity of the rigs is much higher than it is in open water. At present, it is not clear whether this is a purely concentrating phenomenon or whether the structures generate a net increase in overall biomass. Further, no link between the Gulf platforms and the principal commercial fishery, the shrimp fishery, has been demonstrated. Most of the shrimp fishermen would just as soon see the platforms disappear; the recreational fishermen most certainly would not.

Since any Georges Bank structures would be in excess of eighty miles offshore, no recreational fishing activity would take place whatever the effect of the structures.* With respect to commercial fishing, while it is likely that the additional surface area provided by the platform will increaseproductivity locally, the best guess based on Gulf experience appears to be that such increase will not have a noticeable effect on commercial yields given the inability of fishermen to exploit this effect by means of a commercially viable technology. Indeed, if the structure is acting purely as a concentrating phenomenon, it is conceivable that the structures could cause problems for the commercial fishermen by lowering yields in surrounding areas due to the attraction of fish to the platforms. At present, there is no evidence which suggests the platforms lower yields in neighboring areas. Given present knowledge and technology, the

*Hopefully.

platform-as-reef argument would not appear to have a noticeable effect on regional income.

I.6.5.3 Interference with trawling due to sea bottom obstructions

In the Gulf, there are roughly fifty claims a year from shrimp fishermen alleging loss or damage to nets due to fouling with oil-related bottom obstructions. The principal culprits in this regard are "stubs" resulting from the now abandoned practice of cutting off shut-in or abandoned wells above sea bottom to facilitate re-entry, which was a lease maintenance requirement. This practice is now illegal and presumably would be so on the Bank.

This leaves the pipelines. There have been frequent foulings of pipelines in nearshore and bay areas reported in the Gulf. However, there are only two documented cases of offshore pipeline fouling. One involved a line in which burying was interrupted due to bad weather. Subsequent fisherman complaints led to diver-inspection which revealed several hung-up nets. The other culprit turned out to be a concrete block probably used as an anchor for a lay barge and lost. Other inspections of pipeline complaints have yielded negative results. In short, unburied pipelines can foul trawl nets.

The relatively unconsolidated top level sediments of Georges Bank will allow lines to be jetted. From the fisherman's point of view this is superior to trenching, which tends to leave a spoilbank on which trawlboards can and have been fouled in shallow water.

Pipelines have re-emerged. Most re-emergences have occurred in waters of approximately thirty feet or less after hurricanes, due to bottom scouring. Periodic inspections reveal re-emergence and rejetting is instituted. As indicated earlier, there have been no reported foulings associated with these re-emergences. Tidal currents up to one and a half knots have been measured on the Bank. There appears to be no public investigation of the effect of bottom currents on the stability of buried pipelines. We have attempted no such study. It obviously deserves some attention before the depth to which a line should be buried can be decided.

In the Gulf, a rather rudimentary compensation system for fishermen's losses due to underwater fouling has been developed. The fisherman presents a claim and LORAN location to the company he thinks is responsible, or if the fisherman doesn't know which company, to the Geological Survey. The company (Geological Survey) checks the location against location of underwater installations. If there is a match, a diver is sent down. If the diver finds remnants of the net, the company pays for the lost gear. All settlements so far have been out of court. The settlement amount is thus private, but the general consensus among third parties is that the companies paid only for the loss in equipment. An issue which a Georges Bank regulatory body may want to address is whether an explicit compensation system including losses due to down time should be set up.*

In summary, the documented incidence of offshore pipeline foulings in the Gulf has been quite low. It appears that, even assuming a large increase in incidence, the loss in regional income due to such foulings would be small. These two statements assume all offshore lines would be buried.** If a responsive compensation system were set up, the net loss to fishermen could be made small. The Gulf experience suggests that such a compensation system will require explicit regulation. Bottom scouring on the Bank deserves some investigation before the depth to which a pipeline should be buried can be decided.

*The loss of a net, trawl boards and some line would amount to three or four thousand dollars; the income lost would very roughly average about $1000 per day of down time.

**At present Gulf regulations require only that lines be buried in less than 200 feet of water. The technology now exists or will shortly be available to bury lines in up to 400 feet of water.

I.6.5.4 Interference between trawling and seismic activities

To put it euphemistically, the most spirited conflict between the Gulf commercial fishermen and the oil industry has resulted from the fact that both seismic vessels with their 400-ft. arrays and trawlers like to travel in straight lines. The resulting conjunctions have at times escalated to exchanges of rifle fire and the exploding of seismic charges near fishing vessels.

This situation in the Gulf has been met by a mutual agreement to the effect that a seismic boat has right of way over an individual fishing boat but a fishing fleet has right of way over a seismic boat, a fishing fleet being defined to be more than x boats within y distance of each other. Such agreements have been reasonally well observed and the conflict has de-escalated to occasional cursing matches. It is doubtful that this conflict ever had a noticeable effect on either fisherman or oil industry income. Explosive charges are rarely used as seismic sources any more. There is no evidence that such charges affect fish more than a small number of yards from the source. Louisiana has regulated the amount of the charge, the depth to which it can be set, banned night seismic activities, seasonally restricted seismic activity in certain high productivity areas, and placed a State Inspector on each seismic boat to see that these regulations are observed.

In summary, the fishery-seismic conflict appears to be of little economic consequence. However, it is a highly visible, emotionally charged point of conflict which, on the basis of Gulf experience, can be ameliorated by judicious regulation. As such, it should be an explicit subject of concern for the body regulating any Georges Bank petroleum activity.

I.6.5.5 Interference between trawling and platforms

As indicated in Chapter I.2, any discovery would be produced from multiple well platforms. Chapter I.2 further concludes that even a very large (5 billion barrel in place), 10-field find would be handled by no more than 25 separate platforms - a wide range of finds by less than 10 independent structures.* Experience with the fisheries in the Gulf of Mexico indicates that fishing boats generally operate no closer than one-half mile to the platforms. Discussions with both New England fishing captains and consultants indicate that a 1/4-1/2 mile standoff would be a reasonable figure. We will use a standoff radius of one-half nautical mile. It should be noted that fishing operations generally stay at a given depth for a particular tow and thus tend to orient along bottom contour lines. Should a series of platforms be placed such that they form a linear connecting pattern across contour lines they would interfere much more than if they were all on the same contour line. Since independent platforms will be separated by at least two miles, even for a rather shallow (5000 ft.) discovery, we will ignore this interrelation and assume that all platforms are separated by more than the standoff distance.

The loss in fishery output due to the area usurped by each platform will depend on

a) the catch that would have been made in the exact area denied;
b) the extent to which non-fishing in that area affects yield in surrounding areas;
c) the marginal yield in the area to which the vessel transfers the time that would have been spent in the desired area.

As we have seen, the 1969-1970 yield of an area depends quite markedly on the geographical location of the area in question. It also undoubtedly depends on time. One of the biggest unknowns in an analysis filled with unknowns is what will be the future yield of the Georges Bank fishery assuming no petroleum development. Figure I.6.4 indicates the sharp decrease in yield of scallops and haddock, two of the highest value species over the last decade. A straightforward extrapolation of such trends leads one to the conclusion that

*For the purposes of this chapter, a "platform" is one or more jackets unconnected by walkways. The processing and quarters structure for a large field will generally consist of two or three such jackets.

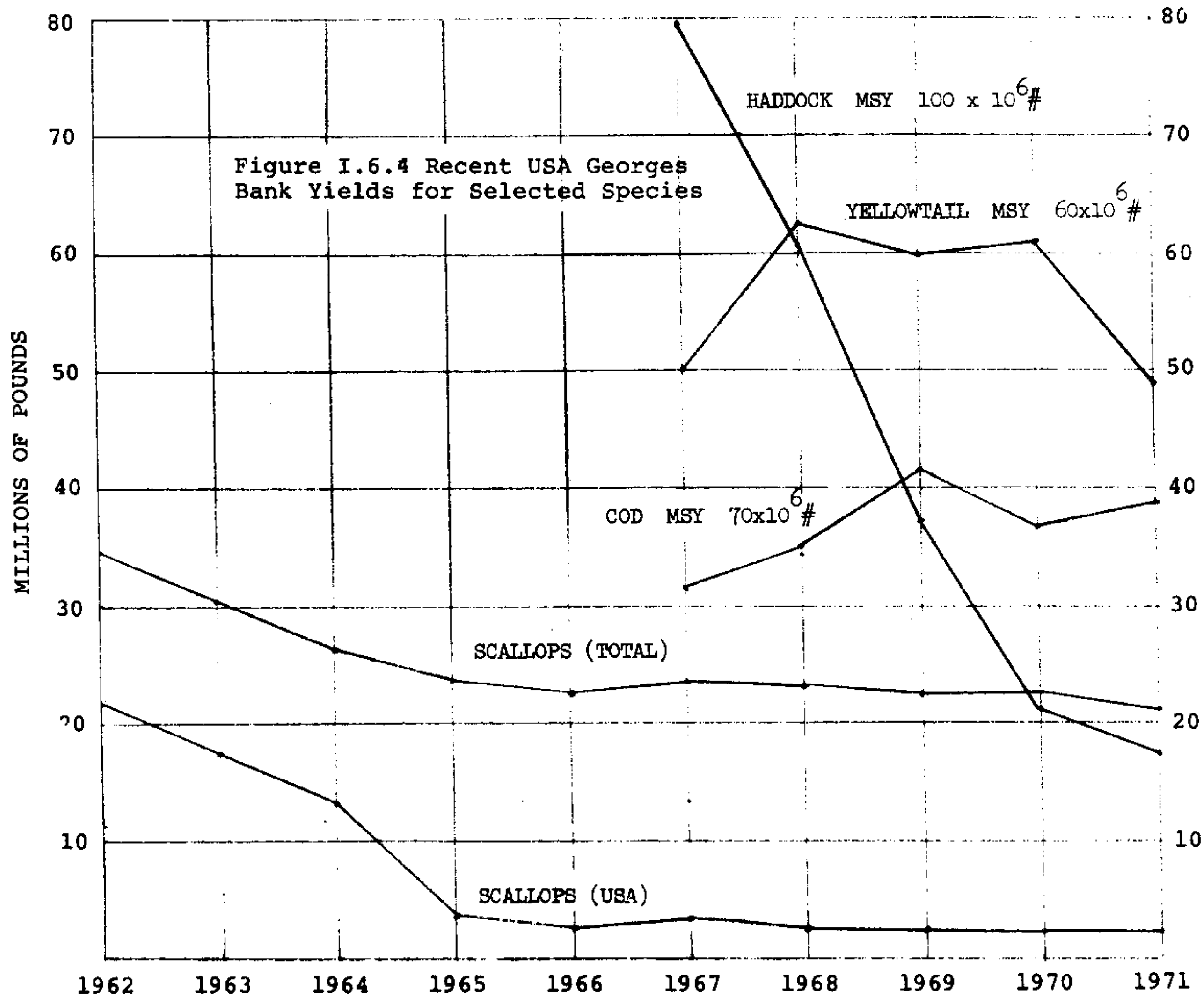


Figure I.6.4 Recent USA Georges Bank Yields for Selected Species
MILLIONS OF POUNDS
HADDOCK MSY 100 x 10^6#
YELLOWTAIL MSY 60x10^6#
COD MSY 70x10^6#
SCALLOPS (TOTAL)
SCALLOPS (USA)
80
70
60
50
40
30
20
10
1962
1963
1964
1965
1966
1967
1968
1969
1970
1971

for at least certain species there will be no fish left to deny any one. On the other hand, Brown and others have estimated that a properly managed Georges Bank fishery could yield 315,000 tons of high-value species annually See Table I.6.5.

Table I.6.5

Estimates of Maximum Sustainable Yields for Georges Bank (tons per year)

Cod	35,000
Haddock	50,000
Yellowtail	30,000
Red Hake	50,000
Silver Hake	100,000
Winter Flounder	10,000
Other Flounder	10,000
Sculpin	10,000
Other Groundfish	20,000
	315,000

Reference ICNAF Research Document 72/119 (June 1972)

Under these two assumptions, let's start with a "worst" case. Assume that the development requires 25 unconnected platforms and a standoff radius of 1/2 mile. The area denied will be approximately 20 square miles or about 24% of a grid square. Now suppose all these platforms were placed in the highest productivity square, No. 50, and that the fishing effort previously directed here would have no return in different areas.* Using 1969-1970 yields, the gross value of this square is about $650,000 per year; assuming Table I.6.5 yields, the gross value would be approximately $1,500,000. Assuming no alternate yield, the drop in ex vessel value would be about

*Distributing the Canadian scallop catch over the South Channel Area results in about $300,000 per square, or at the 50% assumed New England consumer per square, or at the 50% assumed New England consumer share about $150,000/square which does not change square No. 50's highest ranking position.

$150,000 per year and $360,000 per year respectively. Assuming no transfer of resources out of fishing, this is the direct loss in regional income due to the platforms. It will be distributed among fishermen and consumers, depending on the degree to which price responds to the drop in supply.*

In addition to the direct loss, there will be indirect effects on both the input and output sides. Insofar as the loss falls on the fisherman, his drop in real income and hence decrease in spending will induce a net multiplier chain which will be localized in the fishing community. Labor accounts for 65% of the fishery input. Applying a generous 40% (see Chapter I.5) differential between regional cost and market wage rates in all the respending markets would, after multiplication, add another 67% to the loss. Thus, if the whole loss falls on the fishermen, a generous estimate of the net loss in regional income on the input side is about $250,000 per year at present yields and $600,000 per year at assumed maximum sustainable yields.

Under the no price change assumption, there would be no loss in income to consumers. However, to the extent that

a) the drop in Georges Bank fish was not made up from other sources, and
b) the resources employed in processing and retailing fish did not respond to the change in retail rates by transferring to other employment,

there would be a loss in regional income through a decrease in processor and retailer income. The retail value of fish is between three and four times the ex vessel value. However, considerable substitution from other sources would be likely to occur and while first-level wholesalers and some local processors would undoubtedly suffer losses, retailing (largely

*The market is almost purely competitive. Both demand for and short-run supply of fish are relatively inelastic. Thus, one would expect the price to respond. Insofar as this is not true, the drop in Canadian catch would not result in a loss in regional income.

supermarket and restaurant) resources, which account for the bulk of retail value, are highly mobile in the sense that most of these establishments can switch to a slightly different mix of products with almost no dislocation of labor.

In 1968 there were 534 fish and shellfish wholesale and processing organizations in Massachusetts and Rhode Island employing some 9225 people. Assuming a direct reduction in employment equal to the percentage loss in value ($360,000/ $75.7x10^6$), under the severe assumptions, would result in a loss of about 180 fish-processing jobs in the region. Assuming these people had zero opportunity value, this would result in a loss of regional income of about $150,000. Applying a net multiplier chain based on a 40% differential between regional cost and market wage rates in all respending markets would add $100,000 to this figure.

Thus, under the "worst" case a large number of platforms placed in the highest yield square, no return on redirected fishing effort, no alternate opportunity value for fishermen and first-round processors, and a generous estimate of net multiplier effects, we obtain the following estimates of present value loss in regional income due to area denial for the two hypotheses about future yield for a development beginning in 1976:

Table I.6.6
"WORST" CASE PRESENT VALUE LOSSES DUE TO AREA DENIAL

	(Hypothesis (a) 1969-1970 Yields		(Hypothesis (b) Assumed MSY	
	8%	15%	8%	15%
Direct Loss to Fisherman/Consumer 150, 360	1,450	480	3,470	1,150
Net Multiplier Chain Induced 100, 240	960	320	1,230	760
Indirect Loss to Processors	1,450	479	347	1,150
Net Multiplier Chain Induced	960	320	1,230	760
Total (Thousands of Dollars)	4,820	1,600	9,300	3,820
Regional Cost/Platform	$194,000	$64,000	$272,000	$154,000
Imputed Land Value/Acre	310	100	410	240

In short, assuming 1969-1970 yield levels and a "worst" case throughout--large number of platforms placed in highest yield areas, no alternate opportunity value of fishery and first-round wholesaler resources--leads to estimates of present value losses in regional income due to area denied in the neighborhood of five to ten million dollars for 8% cost of capital and two to four million dollars for 15%.

Less severe sets of assumptions will drop this estimate sharply. For example, assuming 25 platforms located in areas of <u>average</u> Georges Bank productivity, keeping all other assumptions the same, will drop the above estimates by a factor of five. Assuming all the platforms are located along the southeastern edge of the Bank will drop the estimated loss still further.

In all the above sets of hypotheses, it was assumed that fishermen have little or no alternate employment opportunities. Indeed, as we have seen, the top boats are reasonably well-paid and it is doubtful under present circumstances if these people, with their rather specialized skills and experience, could find alternate employment at anything close to the same wages, although the assumption of zero alternate opportunity value is clearly conservative. There is at least one set of assumptions under which this might no longer be true. A large-scale petroleum development would require two large workboats per platform during the construction and drilling period and one workboat per field during the entire production period. In short, a large find of the type we have been analyzing would result in at least five and perhaps ten, ten-man workboats operating on the Bank. The North Sea experience suggests that these crews will be drawn largely from local vessel operators, primarily ex-fishermen. Thus, even under the above severe assumptions about loss in yield due to area denial, fisherman employment may actually increase.

In summary, if peak productivity area on the Bank were exchanged in a competitive market it would sell for between

$100 and $400 per acre depending on the owner's cost of capital and fishing management scheme, assuming no cost to this individual of landing his catch. An average piece of land on the Bank would sell for between $20 and $80 per acre under these conditions. These values measure the income forgone by the region to the extent that the development denies such areas from fishing and the fishermen and vessels so affected have no other employment opportunities.

Although even under extreme assumptions these regional costs are small compared to other swings in regional income associated with various developments, a goodly portion of these costs may fall on a very limited segment of the regional population, which group will not receive any direct compensation for this loss under the present rules of the game.

I.6.6 The impact of a large spill

In Chapter II.5 it is concluded that the evidence collected to date strongly suggests that adult fin fish populations will not be materially affected by an offshore spill. It is further concluded that the weak link in the fin fish system is the floating larval stage. Not only are the larval stages sensitive to much lower concentrations of oil, most of these larvae spend a portion of their life floating on or near the surface, where they would be exposed to high concentrations in the event of a spill. Therefore, we will focus our attention with respect to the regional income impact of a large spill on the Bank on the larval problem.

Table I.6.7 and Figure I.6.5 summarize what is known about the spawning period and location of the most important species. The typical sequence of events involves the distribution of fertilized buoyant eggs throughout the wind-mixed surface layer. Incubation takes 10-14 days. The initial larval stage feeds on the egg yolk for another 6-10 days. The larvae then begin feeding on zooplankton. The larvae exist as passive plankton subject to surface drift during the next 1-2 months. 3-4 months after spawning the larvae begin to assume habits typical of the adults.

Two important exceptions to this scenario:

1) Herring and Winter Flounder have benthic eggs (but larval stages are planktonic).
2) Herring larvae demonstrate some active vertical migration.

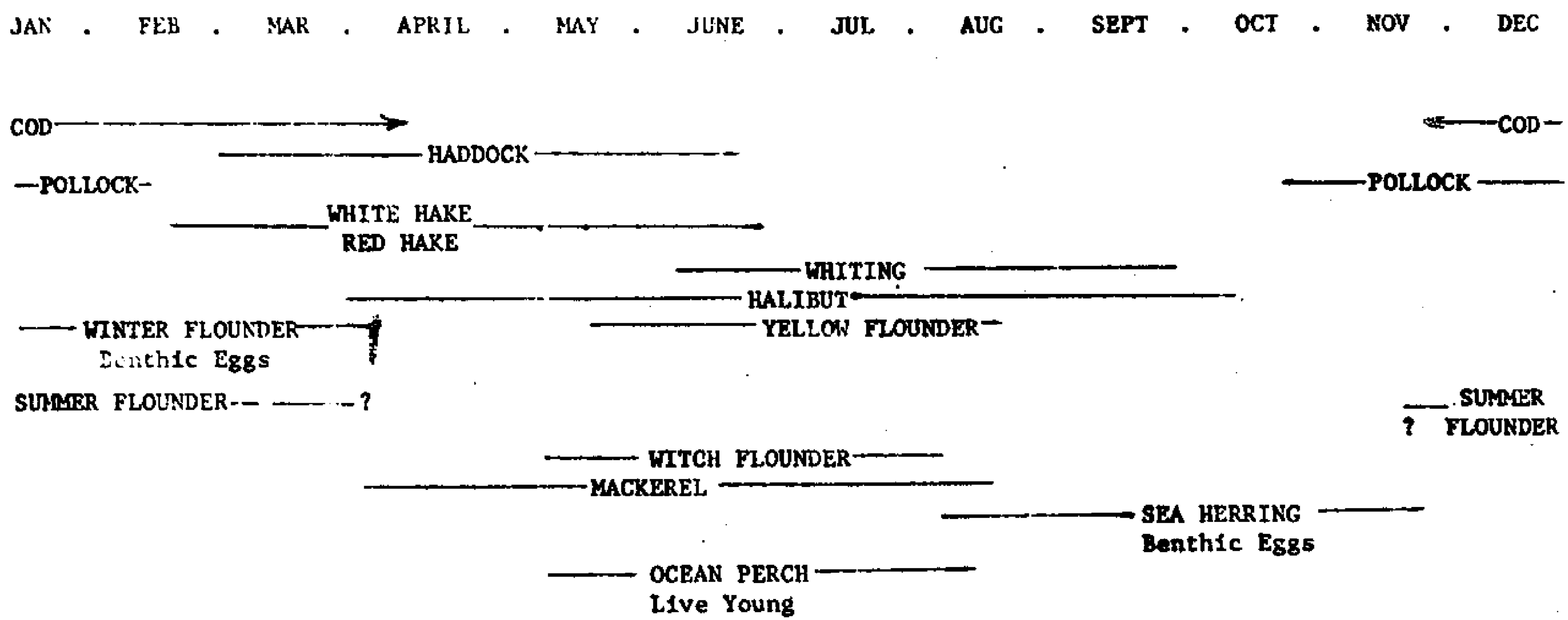
There are no estimates of the time distribution of egg release beyond the identification of range of spawning season and maximum spawning as given in the table. Females typically release 500,000 to 1,000,000 eggs per year for the larger species. The female herring and some flounder species may release only 30,000-50,000 eggs per year.

Plankton tows typically find larvae at depths up to 20 meters, but most are very near the surface. Flatfish larvae (flounders) may be more abundant below 20 meters.

SPECIES	SPAWN SEASON RANGE	SPAWN SEASON MAX	SPAWN. TEMP. °F	SPAWNING AREA
Silver Hake (Whiting)	June-Oct.	July, Aug.	50-60	Coastal ($<$50 Fathoms) Cape Cod to Grand Manan
Cod	Nov.-April	variable	41-47	Coastal and on Georges Bank (See Map)
Haddock	Feb.-May	April	40°	Primarily on Georges Bank (See Map) some coastal
Pollack	Nov.-Feb.	Dec, Jan.	40-45	Mouth of Mass Bay and eastern slope of Stellwagen Bank ($<$50 Fathoms)
White Hake/ Red Hake	Feb.-June	?	?	Coastal (not well known)
Halibut	April-Sept.	April-May ?	40-45	no distinct areas; throughout the Gulf of Maine (possibly greatest on southern slope of Georges)
American Dab	March-June	April-May	?	no distinct areas; throughout the Gulf of Maine
Summer Flounder	(not	well known)		no distinct areas; throughout the Gulf of Maine
Winter Flounder	Jan.-May	Feb.-March	32-37	no distinct areas; throughout the Gulf of Maine
Herring	Aug.-Nov.	Sept,Oct.	46-52	Bay of Fundy; Maine Coast; possibly on Bunk in same region as Haddock

Table I.6.7

FIGURE I.6.5
SPAWNING SEASONS
Gulf Of Maine Fish



With respect to area of the high value species, haddock and cod appear to exhibit the most concentrated spawning. Figure I.6.5 illustrates the general spawning areas for these species. Cod appears to be the most concentrated with a spawning area of roughly 3000 square miles.

In order to obtain an estimate of the larval kill from a spill, we will make the following assumptions:

a) We will assume that eggs are generated through the spawning season according to a bell-like distribution in which the maximum egg production rate is 1.5 times the seasonal average.

b) We will assume a spill occurs during the time of peak egg generation. Thus, we are performing a moderately worse case analysis.

c) Eggs and larvae will blow around like an oil spill once they are on or near the surface. Under this assumption, the larvae must initially rise into a slick in order to encounter oil.

d) All larvae which rise into a slick are killed.

Under these assumptions, the percent of a year class killed, K, will be

$$K = Q \cdot A \cdot T$$

where Q is the peak flux of eggs to the surface (measured in percent of Year Group/square-mile day), A is the area of the spill, a function of the volume spilled, and T is the time that the spill is over the spawning grounds.

The spill simulation model of Chapter II.2 was run to determine the mean time a spill released at a given point would be in these spawning grounds. Initial spill location was varied to maximize this time. The results indicate that the time a spill will stay within a subarea of the

Bank is proportional to the total time on the Bank, $\overline{T}_{GB}$, times the square root of the ratio of the area of the subarea A_{SG} to the area of the Bank, A_{GB}. Stewart (1973) offers a theoretical argument for this result.

Combining this result and Figure I.6.6 we have

Species	Season of Peak Egg Production	$\overline{T}_{GB}$ days	$\left[\frac{A_{SG}}{A_{GB}}\right]$	T days	Length of Breeding Season days
cod	winter	11	1/4	5	150
haddock	spring	25	1/3*	14	110
herring	fall	18	1/3*	10	110

Assuming a peak egg production 1.5 times that of the average leads to

Species	Max Flux Rate % year class/sq mi day	% killed/sq mi of spill
cod	3.5×10^{-4}	1.75×10^{-3}
haddock	3.5×10^{-4}	4.9×10^{-3}
herring	3.5×10^{-4}	3.5×10^{-3}

The resulting ratios of K/A are small enough so that even

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*It is highly unlikely that spawning grounds in the northeastern corner of the Bank will be affected by a spill on the Bank given prevailing winds and currents. See Figures II.2.8 and II.2.10.

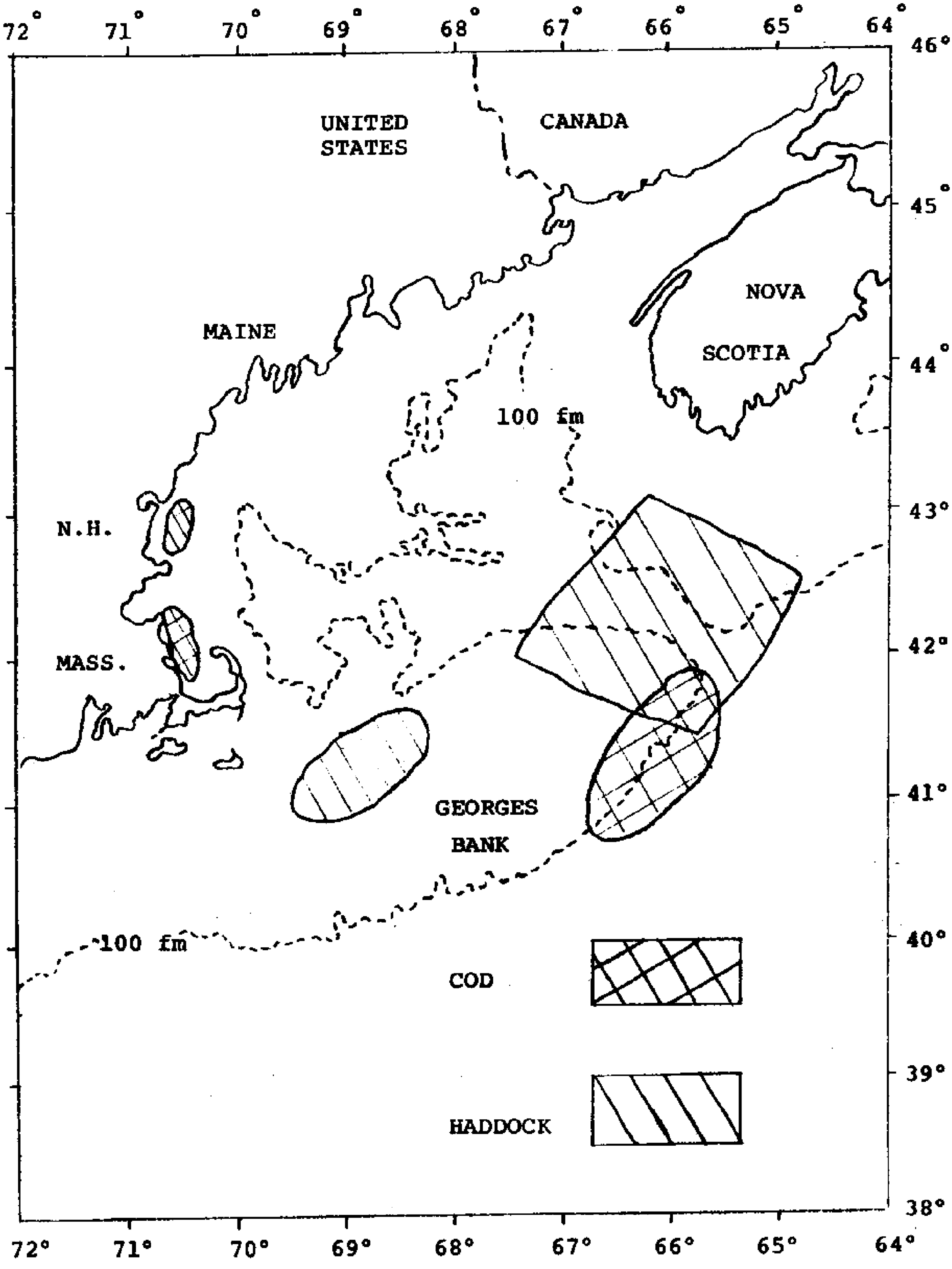

Figure I.6.6

COD AND HADDOCK SPAWNING GROUNDS

assuming an extremely large spill of 28 million gallons ("Torrey Canyon") which would cover about 200 square miles, less than 2% of the year class would be killed under these assumptions. While we have no firm basis for concluding that such a kill would not be propagated into the adult population, it appears that the spawning periods are sufficiently spread in space and time to be relatively stable against the single large spill.

Of course our errors in estimating the various parameters are large and it is conceivable, although unlikely, that the flux could be underestimated by a factor of 10, but even this yields for a very large offshore production spill (2 million gallons) a result that is so small that we cannot estimate its importance with respect to adult populations. See Chapter II.4 for a discussion of what we presently know about the population dynamics of these species.

Another uncertainty is the validity of the assumption that the eggs are generated uniformly over the spawning grounds. It is conceivable that there could be large spatial variations in the egg production. Unfortunately, the dispersive processes are so great and the sampling techniques are so crude that we have no estimates of this property. Also, if spawning is highly localized, then it seems probable that we shall have partially counterbalancing effects. While the flux will increase, the probability of traversing the area will decrease and the time during which the spill is over the spawning ground will decrease. In summary, it appears unlikely that a single spill could kill enough larvae to have a noticeable effect on adult populations. Nature appears to have provided a reproductive process which is relatively insensitive to very short run phenomena.

Tainting.--It is not necessary for a spill to result in a large kill for it to have an impact on the Georges Bank fishery. If, for example, the spill affected the taste of the fish, their economic value would be sharply decreased. With respect to a spill which stays offshore, the weak link appears to be the scallop, due to this filter feeder's ability to concentrate hydrocarbons. Quantitatively, very little is known about the scallop's reaction to hydrocarbons. However, there is fragmentary evidence that filter feeders can convert parts per billion into parts per million in short periods of time. Mussels placed in 30 parts per billion naphthalene for four hours have exhibited hydrocarbon contents of 7 parts per million. A 5-gram scallop processes a liter of water a day on the average, sometimes more. Chapter II.5 estimates that filter feeders have the ability to multiply concentrations by a factor of 1000 or more per day, assuming all hydrocarbons processed were retained.

The mean drift of a spill on the Bank in the summer is .3 knots, which means that on the average an extremely large spill ("Torrey Canyon") will be above a single point on the bottom for about 2½ days. Thus, given a very large, slow-moving spill, concentration factors of several thousand are possible.* Shellfish taste becomes affected at concentrations somewhere between 5 and 50 parts per million. The question then becomes, is it possible to obtain hydrocarbon concentration of the order of parts per billion on the bottom from a spill?

There have been some attempts to measure the vertical eddy diffusivity of sea water; however, the range of the fragmentary experimental results to date is too large to be of any use to us. The problem is further complicated by the fact that during the early part of the spill's life, the particles that will be found in deep water will be light solubles whose small size gives them large rise time, while late into the spill life, evaporation will lead to high boiling point particles which are heavier than water sinking of their own

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*It is known that filter feeders tend to decrease feeding in the presence of hydrocarbons. However, no reliable quantitative data as a function of concentration is available.

weight. In the face of this complexity, we have not attempted to develop a time-dependent model of vertical oil diffusion although such a model would certainly be a worthwhile undertaking.

Some insight can be obtained from a series of measurements done on the 10,000-ton Bunker C "Arrow" spill which took place in early February, 1970, in Nova Scotia. These experiments, described in Chapter II.2, included a series of plankton net tows and water samples at various depths over a two-week period in late February and early March. (Evaporation was retarded by the low temperatures.) The extremes of the data indicate that concentrations of 10 to 20ppb can obtain to depths of 33 feet, 3 to 0.5 ppb to depths of 100 feet, and, in the deepest samples taken, .2ppb at a depth of 250 feet. It should be remembered, this was a residual fuel, low in solubles but of a high density.* Given the extremely large error inherent in experiments, the uniqueness of the oil, how much weight can be placed on this sort of argument is an open question. Mackin, in investigating the Chevron blowout, found average concentrations of 3 parts per million in bottom sediments at 50 feet as far away as 10 miles downstream of the platform. One sample contained 20 ppm. Aromatics below C_{10} were present in concentrations ranging from parts per billion to parts per trillion in these sediments. This spill was blowing for a month and a half at this locale. Thus, it is certainly possible for oil to reach the bottom to at least these depths. Blumer also found contaminated sediments at 40 feet in the light oil North Falmouth spill. Chevron also measured

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*The "Arrow" case is further complicated by the fact that about 10 tons of dispersants were applied to the spill. By reducing particle size, dispersants will increase vertical dispersion. This is a good argument against using even completely non-toxic dispersants offshore.

in-the column concentrations in the neighborhood of the platform as a function of depth. However, this data will not be made public until all litigation is resolved.

In summary, on the fragmentary evidence available, it appears possible to obtain parts per billion concentrations at the depths of the bulk of the Georges Bank scallop fishery (20-40 fathoms). On the basis of present knowledge, such concentration could affect scallop taste. However, it should be kept in mind that the track of even an extremely large spill would cover less than 1/50 of the Bank. Thus, it would be difficult for a single spill to affect more than a small proportion of the scallop population. Further, there is evidence that if the exposure is not prolonged, the organisms will cleanse themselves of most of the hydrocarbons. A complete model of vertical dispersion of oil in sea water appears to be a feasible and useful research undertaking. Scallop hydrocarbon feeding and cleaning habits also need study.

I.6.6.1 Impact of the "red tide" effect

There is yet another way a large spill could affect the fishery which does not necessarily involve any biological damage. This would be the case if demand for Georges Bank fish dropped sharply as a result of the spill publicity, the "red tide" effect. A sharp, transient decrease in demand would allow no reallocation of resources and thus generate temporary overcapacity in fishing, fish processing and marketing with a resultant loss in regional income. However, the "red tide" experience also suggests that this is a strictly temporary phenomenon, lasting less than a month. Insofar as volume caught is unaffected, the loss in fishery-related industry income due to price drop will be matched by increase in real consumer income. Since almost all Georges Bank fish is consumed in New England, such a price decrease will be a wash as far as regional income is concerned. However, this will be little comfort to the fisherman. In any event, the transient nature of the red tide effect, the fact that no resources, or, at most, a small portion of the fish in the processing and retailing process at the time of the drop.in demand, would be destroyed, argues strongly against this phenomenon having a siginificant effect on regional income. Once again, however, there will be a transfer from the producer to the consumer without, under present rules, compensation.

I.6.7 The impact of continuous discharges

The concentration of production on a handful of high-volume platforms is not an unalloyed benefit as far as the environment or the fishery is concerned. It has the effect of concentrating the production-associated discharges in a small number of locales, which could at least conceivably lead to harmful hydrocarbon concentrations in the vicinity of these platforms. The purpose of this section is to investigate this possibility.

According to Chapter I.2, a single large separation platform could process 200,000 barrels of oil per day.* Currently in the Gulf, the offshore fields are producing 400,000 barrels of water per day and 1.1 million barrels of oil. This ratio is rather high for offshore fields. Assuming this water is separated on the platform to current Geological Survey standards (50 parts of oil per million parts of water), such a platform would discharge about 125 gallons of oil into the water per day, at a discharge rate of three cubic feet per second of effluent.**

There appear to have been no studies of the composition of the oil remaining in the water after separation by fraction. Several oil industry sources are of the opinion that this oil will be similar to the crude being produced. The study group regards this as unlikely. The process is essentially gravity separation aided by emulsion breakers usually followed by gas flotation. This process is essentially ineffective with respect to that portion of the soluble fractions which is dissolved into the water. Given

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*Phillips intends to separate 800,000 barrels of oil per day from gas on a single platform in the North Sea. However, one of the reasons they are able to do this is that they expect very little water.

**It appears that the Gulf platforms are currently meeting the Geological Survey requirement most of the time. Further, there is no technological reason that a system designed from scratch could not meet it all the time.

present information available to us, we cannot rule out the possibility that the bulk of the oil remaining in the water will be made up of the more toxic soluble aromatics.*

Given this possibility the question then becomes: what concentrations of this oil can we expect in the waters surrounding such a platform as a result of this continuous discharge?

The waters into which this oil is discharged are subject to tidal, wind-driven, and steady-state currents which average close to one knot in absolute velocity. Thus, the oil pouring continuously into the water will be distributed initially along a wiggly line in much the same manner as a soda jerk distributes chocolate sauce on a sundae by moving the dish around under the dispenser. The oil will then spread outward and downward from this line. In this section, we will assume the oil initially mixes to a specified depth and then spreads in a strictly two-dimensional fashion outward. The resulting computations are considerably simpler than those for three-dimensional spreading which involves dispersion both outward <u>and downward</u>.

The results of this two-dimensional calculation should be regarded as ballpark estimates only since reservoir water is typically heavier than sea water. Being heavier, the discharge will tend to sink, enhancing the mixing process and reducing the areal extent of the region subjected to high concentration. Since the water on Georges Bank is virtually unstratified, the depth of mixing will be limited only by the bottom. The depths over much of Georges Bank range from 10 to 200 feet.

The presumption that all the effluent will sink assumes that the tower effluent is a homogeneous mixture. In fact, this discharged petroleum is in the form of both

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*Obviously, some rather simple experiments would advance our knowledge in this area a great deal.

small droplets that tend to rise to the surface as well as the soluble portions dissolved in the heavier reservoir water. The buoyant droplets will rise out of the sinking reservoir water and upon reaching the surface will spread until they form a film only molecules thick, causing a surface sheen. This film then undergoes evaporation and oxidation and the remainder is then presumably mixed into the top several feet of water. The oil originally dissolved in the discharge water will remain in solution, mixing throughout the column until it is removed biologically, evaporates, or is absorbed by bottom sediments. Figure I.6.7 shows a schematic representation of the problem.

Clearly, the two-dimensional model represents a great simplification of the problem. However, with respect to area affected, it is certainly a conservative approach, provided we assume mixing depths lower than those which will be obtained. We will here presume that the mixing depth is in the range of 3 to 10 feet. Our belief is that the 3 foot mixing depth is highly unlikely. This approach will give us an upper bound on the areal extent of the region over which concentrations greater than a specified level will be found.

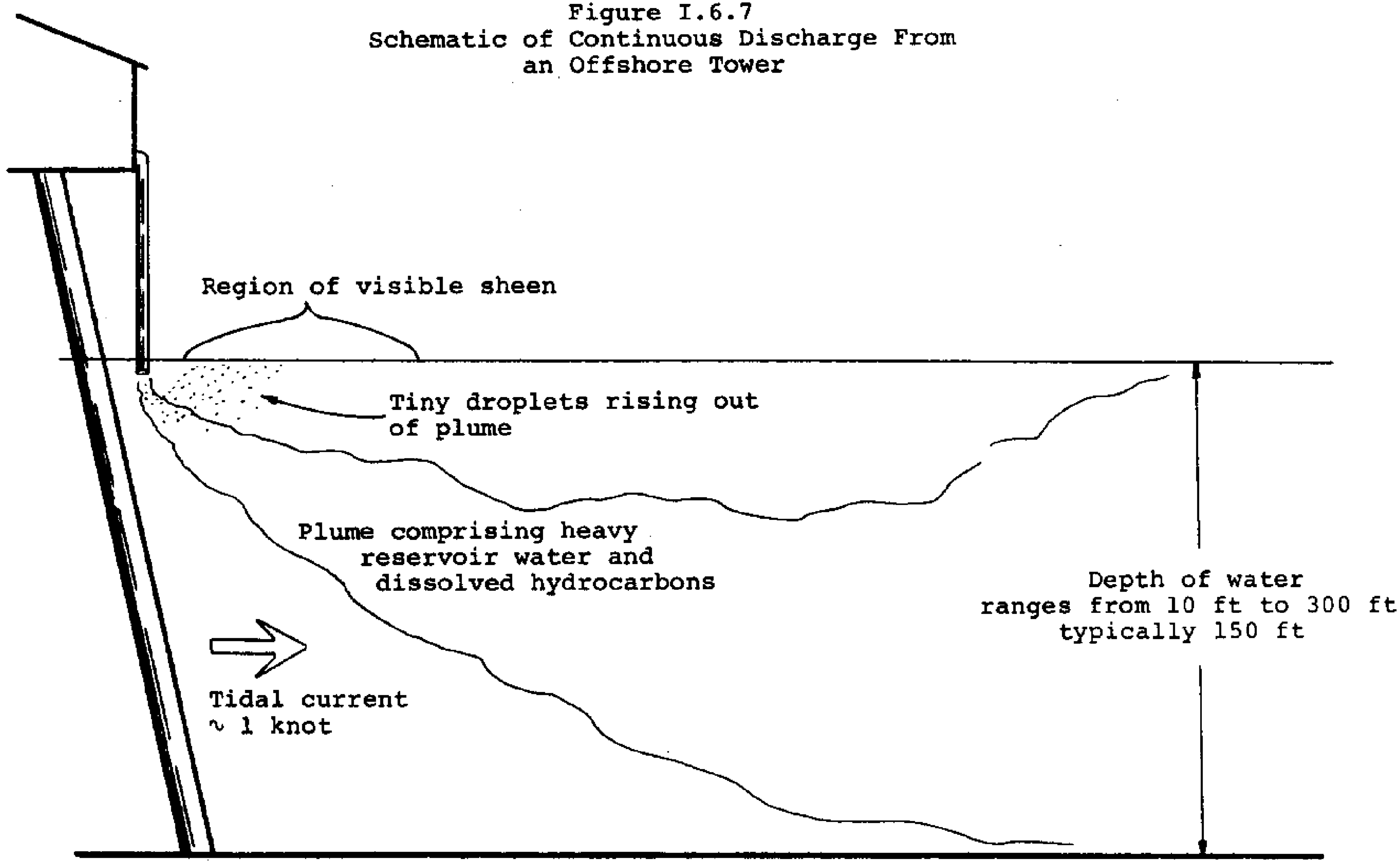
The farfield solution for two-dimensional spreading from a line source is given by

$$c(x,y) \cong \frac{c_o q \exp(-y^2 u/4Ex)}{z\sqrt{4\pi x u E}}$$

where $c(x,y)$ is the concentration at a distance x lying along the direction of the current from the source and at a distance y perpendicular from the current line, c_o is the initial concentration of the effluent, q is the rate at which the effluent is discharged in ft^3/sec, z is the depth to which initial mixing occurs, u is the current speed and E is the dispersion coefficient.* Harleman et al. (1971)

*E is a measure of how rapidly the oil spreads outward.

Figure I.6.7
Schematic of Continuous Discharge From an Offshore Tower



offer empirical evidence that the dispersion coefficient for sea water plumes 10 m to 1,000 m wide lies in the range of 10 ft^2/sec to 30 ft^2/sec. Using this expression, assuming E=30 ft^2/sec, and assuming alternately that the mixing depth is three feet and ten feet, leads to the dropoffs in concentration along the centerline shown in Figure I.6.8.

Of course, we are more interested in the area within which concentrations above some specified level will be found: solving the above expression for y as a function of dilution, $D=c/c_o$, leads to

$$y = \left[-x \frac{4E}{2} \ln \left(\frac{z_o\sqrt{4\pi Eu}}{qD^{-2}} x^{1/2}\right)\right]^{1/2}$$

This expression yields contours within which concentrations exceed c. A pair of such contours is shown in Figure I.6.9. Integrating this expression with respect to x leads to an expression for the area within which concentrations of c exceed a specified level. A computer program was developed that computes these areas as a function of initial discharge rate, initial mixing depth, dilution, and dispersion coefficients. Some of the results are given in Figures I.6.10 and I.6.11. The worst case examined (high [3.1 cfs] discharge rate, low [3 ft] mixing depth, and low [3 ft^2/sec] diffusion coefficient) results in an area of 0.1 sq mi over 100 ppb and .001 sq mi over 1,000 ppb. Increasing the initial mixing depth drops these areas sharply. For example, if the mixing depth is 10 ft, the area within the 100 ppb contour for this case becomes .002 sq mi.* The area within a particular contour decreases in direct proportion to an increase in dispersion coefficient.

All the areas given above are for discharge into water moving at one knot in a straight-line direction.

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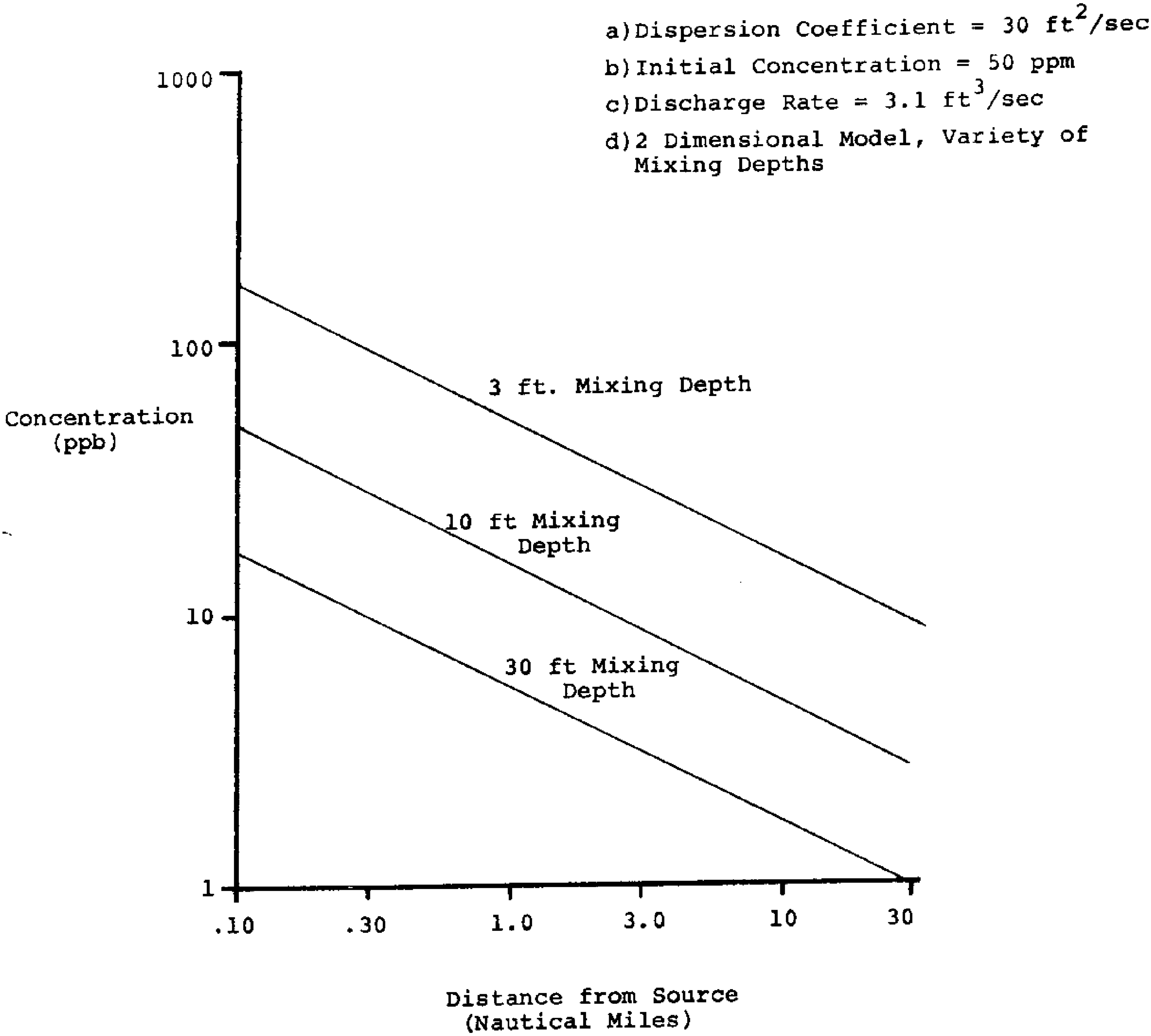
*Interestingly enough for this model, the maximum width of a particular contour is independent of the value of the dispersion coefficient. The length of the contour is sharply dependent on E.

Figure I.6.8

Drop in Centerline Concentration



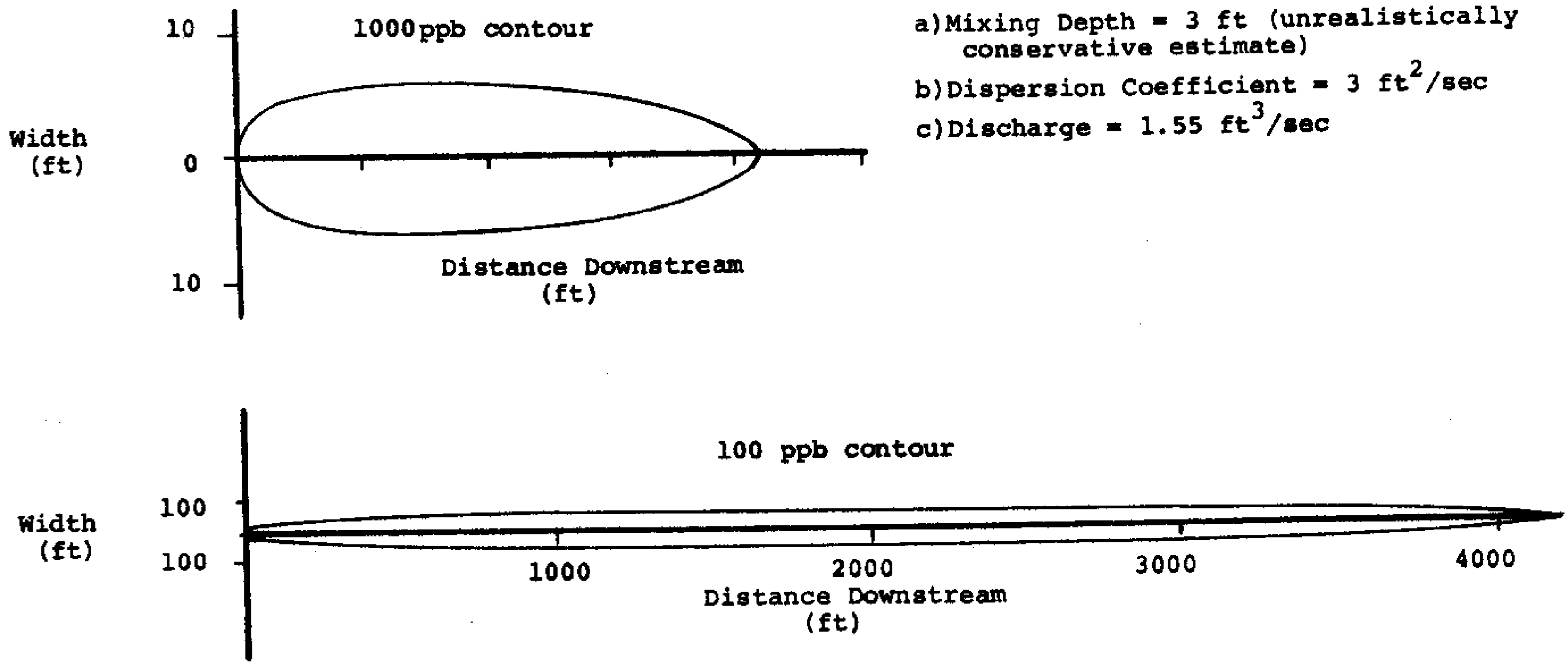


Figure I.6.9

Concentration Contours
(Note scale change between two diagrams.)

Figure I.6.10

Area Enclosed by a Concentration Contour versus Horizontal Dispersion Coefficient

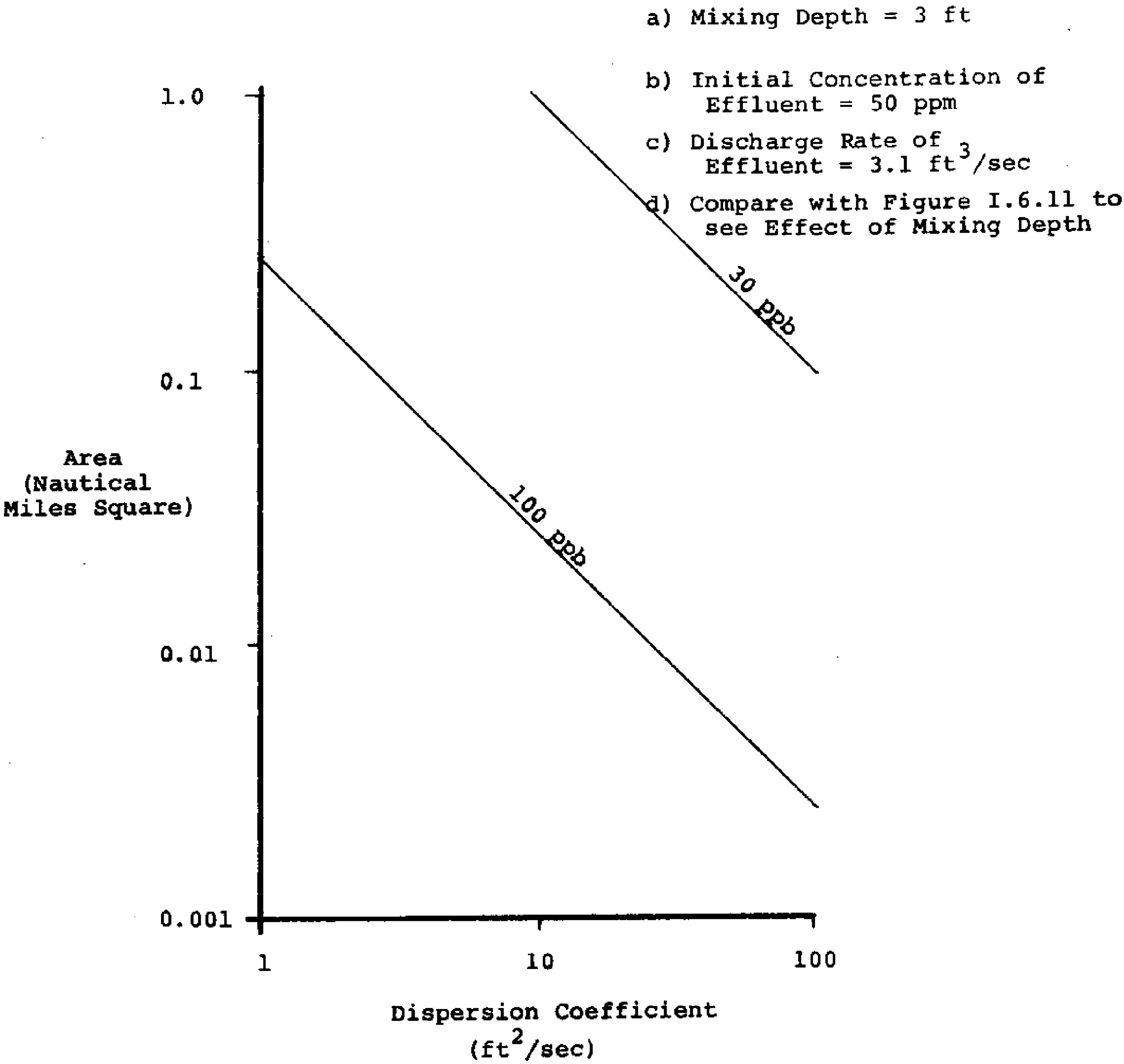
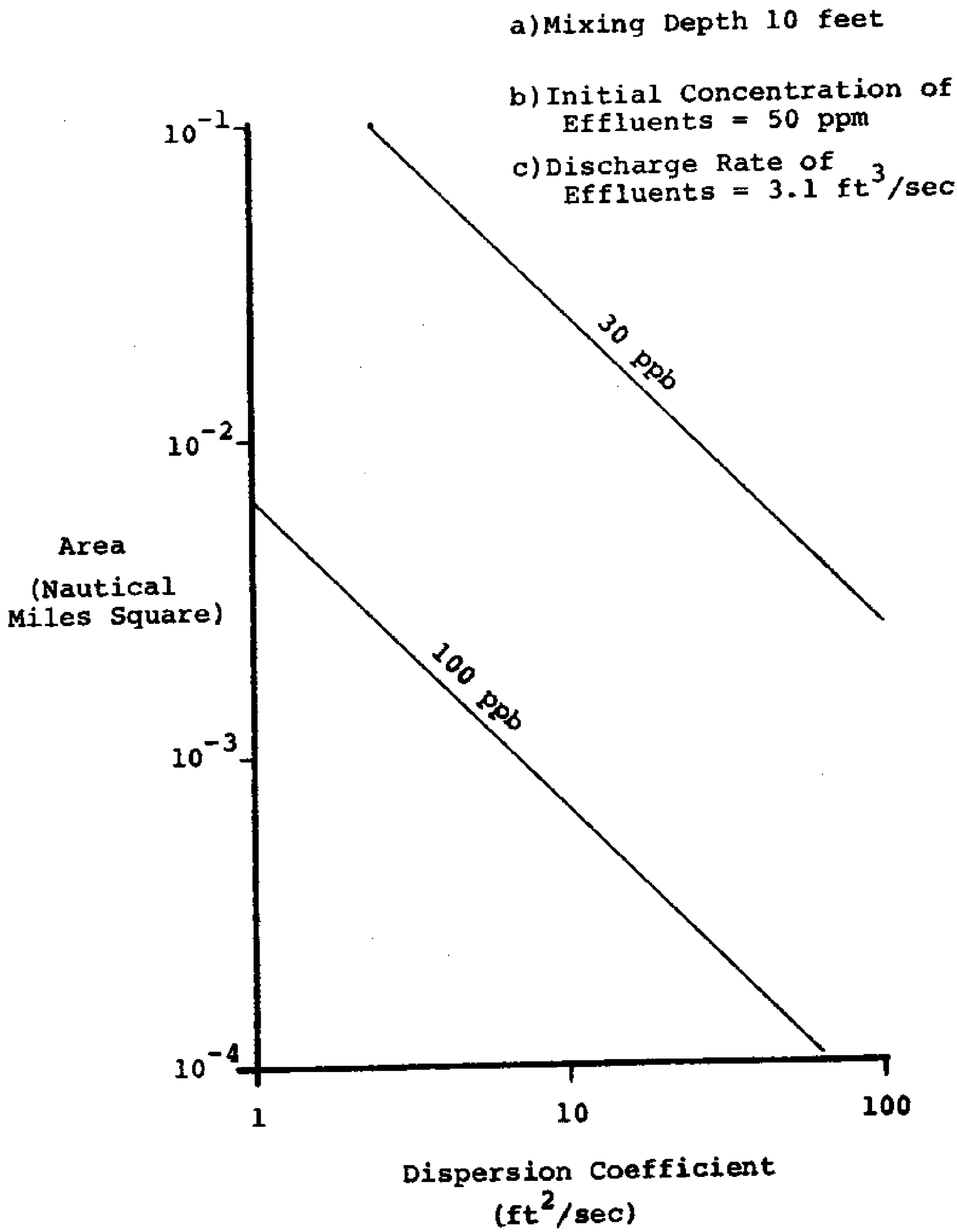


Figure I.6.11

Area Enclosed by a Concentration Contour versus Horizontal Dispersion Coefficient



These numbers essentially assume that the platform does not discharge into the same waters twice. In actuality, the line circles around with tidal cycles and wiggles with the wind and thus can cross over itself. On the Bank, the average tidal cycle has a radius of about 5 miles. The mean drift due to wind and steady state currents is about .3 knots. Thus, on the average, the centerline of the contours actually looks something like Figure I.6.12 in which the line crosses over itself thrice. This will have the effect of tripling the concentrations calculated above within any one contour.

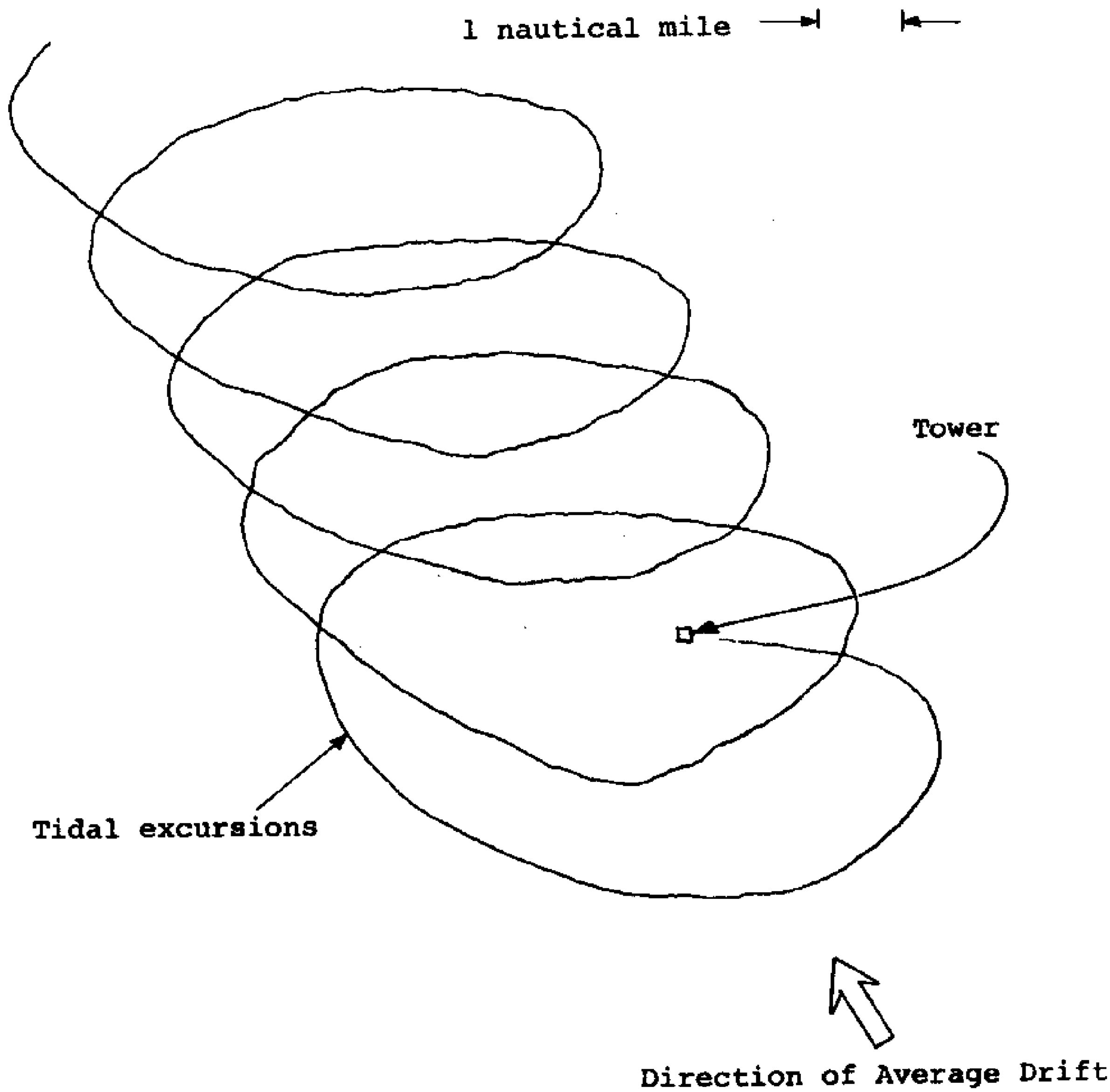
Chapter II.4 offers evidence that the lower level of larval toxicity occurs at approximately 100 parts soluble aromatics per billion. Assume as a worst case that all the oil in the separator discharge is made up of soluble aromatics. To be on the safe side, given the recrossing problem, we should perhaps concentrate on the 30 ppb results.

Table I.6.8
Areas Within Which Concentrations
Will Exceed 30 ppb
(Two-dimensional dispersion, 50 ppm, 1 knot current)

Discharge:	1.55		3.10	
Mixing Depth (ft):	3	10	3	10
Dispersion Coeff: 3 ft^2/sec	.05	.001	2.00	.083
most likely values: 10 "	.01	-	.90	.025
most likely values: 30 "	.005	-		

Table I.6.8 indicates the areas within which the analysis estimates concentrations of 30 ppb or greater will be found for a variety of different assumptions. The largest such area is in the neighborhood of two square miles. Even ten such platforms could affect only a very small proportion of the larvae of even the more concentrated species. At present, it appears unlikely that the continuous discharges of a very large, high water production

Figure I.6.12
Schematic History of Trajectory of Water on Georges Bank with Respect to a Fixed Tower



discovery would have a noticeable impact on the fishery. This finding is consistent with Gulf experience.

However, this same analysis indicates that the margin of safety is not infinite. For example, at the 10 ppb concentration level, it is possible to get the areas to grow very rapidly by choosing extremely unrealistic conditions. Assuming a 1 foot mixing depth and 1 ft^2/sec dispersion coefficient, a high water discharge in which the oil is all aromatics, the area within the 10 ppb contour is roughly 800 square miles. While there is simply no chance that this set of conditions would ever obtain, the sensitivity of area to our assumptions indicates that the problem may merit some study and monitoring. Research needed includes data on oil-water separator discharge by fraction. Especially, what portion of the oil still in the water is soluble aromatics? A study of ambient hydrocarbon levels in the Gulf by fraction and correlation of the results to discharges would be useful. Detailed study of the resevoir water-sea mixing process and subsequent diffusion is also called for and certainly should be part of any discharge diffuser design if sizable volumes of water are to be discharged. THe knowledge required to model these plumes in three dimensions is available.

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Chapter I.7
Regional Impact of Nearshore Spills

I.7.1 Background

Chapter II.5 concludes that, given present knowledge, the most serious biological impact associated with the various petroleum options is the nearshore spill. Chapter II.1 estimates the mean time between nearshore ship spills for a number of hypothetical options (see Table II.1.12). Some of the results are summarized in Table I.7.1.

Table I.7.1 must be interpreted with considerable caution. The right-hand column refers to a range of estimates of the mean of the unknown amount which will be spilled.* The principal sources of error in specifying this mean are:

1) our assumption that the mean amount spilled is proportional to the amount of oil handled (in and out) within the region, which is almost certainly not completely correct;

2) the limited sample size when viewed in light of the extremely widely spread spill volume distributions.

These problems are discussed in Chapter II.1.

The upshot is that our estimate of the mean amount spilled for a particular option can vary by as much as a factor of four. The lower estimates in Table I.7.1 are based on 1971 Coast Guard data, the higher estimates on worldwide reports of large spills for the period 1964 through 1971.

Since in this chapter we are dealing with the impact of spills on the shoreline and since Chapter II.2 indicated that one spill in fifty to one spill in twenty emanating from the offshore towers will reach shore and those that do will be well weathered, in Table I.7.1 we have not included the spillage associated with the offshore production itself.

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*See Chapter II.1 for a definition of the term mean and assumptions used in generating these estimates.

Table I.7.1
Estimates of Mean Large Spill Incidence and Low and High Estimates of Mean Volume Spilled per Year Due to Nearshore Spills for Eight Options in 1978 @ 4% Growth Rate

Option	Description	Regional Volume Handled 1000's bbl/day	Est. of Mean Time Between >42,000 Gal. Spills	Est. of Mean Vol. Spilled Gals./Year
1	No Find No Reg. Ref.	2,400	.50	1.12×10^6 1.62×10^6
2	No Find Reg. Ref. Pres. PDS*	4,600	.90	1.88×10^6 2.84×10^6
3	No Find Reg. Ref. Pipeline PDS*	2,040	.45	$.90 \times 10^6$ 1.86×10^6
4	Large Find No Reg. Ref.	2,400	.50	1.12×10^6 1.62×10^6
5	Small Find Reg. Ref. Pres. PDS	4,600	.90	1.88×10^6 2.84×10^6
6	Small Find Reg. Ref. Pipeline PDS	2,040	.45	$.90 \times 10^6$ 1.86×10^6
7	Large Find Reg. Ref. Pres. PDS	4,600	.90	1.88×10^6 2.84×10^6
8	Large Find Reg. Ref. Pipeline PDS	1,040	.45	$.51 \times 10^6$ 1.90×10^6

*Pres. PDS: products distribution by tanker and barge (assumes Machiasport refinery location). Pipeline PDS: products distribution by pipeline (assumes Dighton refinery location). Small find and all large finds brought ashore by tanker except large find-pipeline PDS brought ashore by pipeline.

However, we have included 25% of the spillage from the offshore pipeline since some fraction of the offshore pipeline spills will occur close enough to shore to have a high probability of reaching shore. However, we have not given this particular problem any quantitative analysis. Consequently, the range of mean volume spilled in Table I.7.1 differs from those shown in Table II.1.11, which displays the estimates for all the oil spilled in the region.

Concentrating on the high estimates, the lowest estimates of mean spillage occur under the options which involve no regional refinery. A regional refinery with a pipeline products distribution increases the estimate of nearshore spillage by about 15%. A regional refinery with the present products distribution system increases the estimated mean of nearshore spillage by 75%. Offshore production has little effect on nearshore spillage for the high estimates.

Under the low (Coast Guard 1971-based) estimates the critical variable is whether the products distribution system is by pipeline. A regional refinery without a pipeline products distribution system approximately doubles the estimate as compared with the present system, while a regional refinery with a pipeline lowers the spillage due to the decrease in secondary distribution by barge. The offshore production has little effect, except for a large find brought ashore by pipeline, which lowers the estimates due to the decrease in incoming tanker traffic. Under the low estimates, the amount of nearshore tanker traffic is all-important. Under the high estimates, it is much less so.

It should be remembered that Table I.7.1 shows a large find at maximum production, so it shows the peak effect of the find. In most years, the effect will be less.

Throughout the remainder of the chapter, we will use the high estimates on the grounds that the larger sample size more than outweighs the incompleteness of this data and decrease in accuracy in determining volumes handled given the importance of the very large spill.

Chapter II.2 investigated nearshore spills occurring at Machias Bay. It was demonstrated that a 1 million gallon spill occurring in the spring or summer threatened locations on the Maine coast as far south as Penobscot Bay and as far north as the Canadian border (see Figure II.2.12). It was shown that a .1 kt SW current swept the spill south, and the zero current case allowed the spill to be blown north.

Figure II.2.12 indicates that the average length of idealized straightline coast affected by at least the remnants of a spill is on the order of 50 miles in summer and considerably less in winter. This length is not to be confused with miles of shorefront actually touched by oil which, on the highly indented Maine coast, may be five to ten times these figures.

Similar estimates for major products unloading locations and for the hypothetical crude receiving terminal off Sakonnet Point have not been made. The reason for this important omission is that a more detailed coastline spill simulation model incorporating current sheer and tidal effects is required for such estimates, the development of which program was not undertaken during the study effort due to time constraints.

For comparison, the amount of shoreline affected by the Santa Barbara spill (best estimate: three million gallons) was about 30 miles. The "Torrey Canyon" spill (about 28 million gallons) affected, very roughly, 140 miles of English and French coastline.

Given the above estimates and the relatively intensive use of much of the New England coast, the impact of shoreline fouling on regional income obviously deserves considerably attention.

I.7.2 The Santa Barbara spill: a case study

Once again in estimating the cost of a spill coming ashore, we must be careful to distinguish between private cost and regional cost, and between regional cost and national cost. We will begin with considering the national cost of such a spill, and then attempt to estimate what portion of this national cost would be borne by the region.

Without analysis which indicates the actual amount and location of waterfront affected by a given hypothetical spill, an estimate of the national cost of that spill is impossible. However, we can obtain some insight into the magnitude of the problem by examining the one complete study of the economic impact of a spill now existing, Mead and Sorenson's study of the Santa Barbara spill (Mead , 1970).* The Santa Barbara spill is particularly interesting for our purposes because the coastline affected was a relatively high-value area intensively used for recreation. Of all the large spills, it is the one which most closely resembles the New England situation from the point of view of shoreline usage.**

Meade categorizes the national cost associated with a spill as follows: (1) Clean-up cost and property damage; (2) Damage to tourism; (3) Damage to commercial fishing industry; (4) Decline in shorefront property values; (5) Damage to the marine environment; (6) Loss of oil; (7) Reduction in recreational opportunities for the resident population.

Clean-up and property restoration.--Meade and Sorenson estimate that the direct cost of clean-up to the oil

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*Walter Mead is a resource economist of national stature who has frequently differed with the oil industry with respect to the import quota and strategies for meeting the country's petroleum defense needs.

**There are, of course, important differences (tidal range, degree of indentation - northern New England; shoreline type, water depths - southern New England).

industry and government agencies was $11.1 million, or about $3.00 per gallon. The oil companies bore the brunt of this ($10.5 million) directly. The breakdown of the oil companies' clean-up and control efforts was: (1) Beach clean-up: $4.9 million; (3) Oil well control efforts: $3.6 million; (3) Oil collection efforts: $2.0 million. Oil collection efforts at Santa Barbara were relatively ineffective. It is estimated that less than 10% of the spill was collected during the early part of the flow, which contained the vast majority of the total amount of oil lost, with perhaps 50% collected during the later stages of the seep. Meade and Sorenson assume that the oil company and government clean-up expenses covered all the nation's cost associated with clean-up. That is, each property owner affected had his property physically restored to pre-spill status at company or government expense. This is undoubtedly not completely true; however, it appears accepted by most that the oil companies did indeed handle the great bulk of the clean-up and that the effect was to restore the property affected to something approaching pre-spill status from an economic point of view.

Effect on tourism.--Perhaps the most surprising conclusion of the Mead study is that the spill had little net effect on volume of regional tourism trade. As Mead puts it:

> We must distinguish between trade destruction and trade diversion, the former meaning an absolute loss in the employment of otherwise fully employed resources, the latter involving the transfer of tourist expenditures to other (regional) areas. Our data indicate that the Santa Barbara oil spill largely diverted tourists to other areas; that the losses of beach front motels and restaurants were offset by gains in other areas.

This conclusion is primarily based on analysis of the California motel-hotel transient occupancy statistics. After seasonal and price adjustments, the "bed tax" receipts in Santa Barbara County rose 3% in 1969 compared with 10% for the state as a whole. Receipts for Santa

Barbara County, excluding the City of Santa Barbara, rose 11%. On this basis, Mead and Sorenson conclude: (a) whatever effect the spill had on tourism, it was confined to the City of Santa Barbara; (b) the decreases in Santa Barbara were matched by increases in other parts of southern California due to diversion. The data certainly appears to back up the first statement; however, the second statement is not completely supported. By its nature the diversion effect is diffuse and could hardly be expected to show up in the statistics. On the other hand, it is possible the decrease in Santa Barbara proper was not matched by increases elsewhere in the region's tourist business, in which case there would be a net effect on regional income due to tourism. In any event, the gross effect is clearly localized and amounts to at most 7% of the County's tourist income and about 12% of the City's tourist income. Since some of this decrease will be matched by decreases in regional costs, e.g. restaurant payments for food, these figures represent upper bounds on the net loss in regional income due to changes in tourism. Mead and Sorenson's estimate that this effect on regional income was negligible is a lower bound. For sharply transient phenomena such as the response to a shoreline spill, the net loss is likely to be a rather large proportion of the gross loss, for most resources will not be able to adjust to the rapid fluctuations in tourist volume.

Damage to commercial fishery industry.--Investigations of the Santa Barbara spill have not revealed any economically sizeable effects on commercial fish species. This is unlikely to be the case in New England, especially southern New England, where shallow-water shellfish are of some importance. Fiske et al. have estimated that the gross annual revenues from Pleasant Bay, a fairly typical high productivity southern New England coastal area, at about $29/acre (1967) per year, almost all of which revenue was based on sessile shellfish.* A three million gallon spill could easily traverse a hundred thousand acres.** Chapter II.5 concludes that if this oil contains an appreciable proportion of soluble aromatics which would be the case for all but residual and some heavy crude spills, extensive kills of adult as well as larval organisms can be expected in all the intertidal areas and surf zones reached in the first few tidal cycles.***Shallow water mudflats and other unconsolidated sediments would accumulate oil which may remain present in appreciable quantities in the substrates for several years, perhaps inhibiting recolonization. Shellfish tainting would almost certainly occur throughout the shallow water (<20') area affected by the spill. Much of this tainting would be transitory in nature, but delays in harvesting of at least several months and perhaps for a year or more could be expected.

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*This is the figure for Pleasant Bay as a whole, some 7,000 acres. The gross revenues from specific high-value flats can be rather spectacular, upwards of $2,000 per acre per year. Similarly, Division of Maine Fisheries estimates for the Merrimack River Estuary were $450 per acre and for Quincy Bay $30 per acre.

**Blumer has identified oil in sediments in a region of over 5,000 acres from the 170,000 gallon North Falmouth spill.

***Preliminary indications are that this was not the case in the "Tamano" spill due, in our opinion, to the composition of the oil (residual) and the calm conditions prevailing for the first several days of the spill which decreased vertical mixing.

In short, partial kills associated with a large spill plus losses in harvest due to tainting could amount to a net loss of several million dollars.* The fact that almost all high-value clam and oyster beds are presently being harvested at maximum sustainable yield and above will tend to confine these losses to delays rather than an absolute decrease in harvest.

In the Santa Barbara case, the effect on commercial fishing was due primarily to the fact that a boom was placed across Santa Barbara harbor for a month, trapping some 75 boats inside. After the boom was replaced by an air curtain, fishermen were still unable to work the local waters because they could not see the fish due to the slick, and the fish were unmarketable due to the coating obtained as the caught fish were pulled up through the slick. Many local fishermen moved out of the affected area for several months. Despite this, fish landings at Santa Barbara for the entire year registered an all-time high. Mead assumes that they would have been still higher and that the fishermen lost two months' wages and profits. The total loss to local fishermen so estimated was a little over $800,000, including an estimated $100,000 in uncompensated property damage.** As indicated earlier for a similarly sized spill in a high productivity area on the New England coast, this loss could easily be several times this amount.

Reduction in value of shoreline property.--Mead and Sorenson surveyed local assessors and real estate dealers. They found a strong concensus that (1) The volume of beachfront sales declined sharply in 1969 and 1970; (2) market values in certain areas involving 250 beachfront properties declined 15-25%; (3) property values not in the immediate

*The Santa Barbara estimates are, in this regard, overly optimistic when applied to a shallow water New England spill. However, the Santa Barbara costs include $3 million in well control which would not be incurred in the nearshore New England spill. Thus, the two effects are very roughly counterbalancing.

**Based on Mead and Sorenson's discussions with local fishermen. The oil companies paid $150,000 to boat owners.

vicinity of heavy fouling were unaffected; (4) there was a feeling that whatever the decline, it is temporary and would disappear within about five years assuming no further spills.

Under these assumptions, the gross present value loss (at 10% cost of capital) in property value is about $10 million. This is not a net loss in national income since, under the above assumptions, the property owner need only hold on to the property for five years, and it will be worth what it would have been without the spill. In the interim, however, his property will be less desirable--he or his renter will have less enjoyment--than it would have been without the spill. The actual loss suffered can be estimated by calculating the forgone rental income. Mead uses the industry rule of thumb of annual rents equal to 12% property value resulting in a present value national cost of $1.2 million or about $40,000 per shorefront mile affected.

Damage to marine environment.--Mead and Sorenson assume that society is willing to pay $2.00 per bird to avoid a known bird killed. 3,686 known bird kills were attributed to the spill. Thus, they estimate the natural losses due to bird kill at $7,000. The point here is that the national cost of the bird kill, the most publicly noticeable impact on the marine biota for this particular spill, is negligible compared to other costs, even if a very high unit value is assumed. No other marine environmental losses are estimated - undoubtedly the result of the biological investigation's failure to uncover extensive toxicity to commercial or publicly esteemed species other than birds.

Loss of oil.--Lost oil was valued at its national cost which the authors estimated at $130,000.

<u>Loss of recreational value</u>.--The most interesting feature of the Mead and Sorenson study is that they undertook to estimate the loss to area residents due to the decrease in quality of beach recreation. They conducted a telephone survey which elicited the following information:

a) The average resident of Santa Barbara County claimed that a visit to the beach was worth 1.75 movies to him.

b) As a result of the spill, beach visits declined from about 28 visits per year per person to about 21.

Meade and Sorenson used the answer to the movie question to estimate that a beach visit is worth about $2.60. They assume (a) there are no national costs associated with going to the beach (transport, congestion); (b) the quality of the visits which did take place was unaffected by the spill; to arrive at an estimate of $3.1 million loss in local recreational opportunities.*

Combining all the above, Mead and Sorenson estimate the national cost of the Santa Barbara spill at about $.6.4 million or about $5.00 per gallon.**

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*Assumption (a) tends to overvalue the effect of the spill; assumption (b) undervalues it.

**The authors asked one other interesting question in their survey: assuming that the oil companies would not pay for the change and that drilling operations would be neither safer nor more hazardous if placed underwater, would you support an increase in state taxes to put the platforms under water? 40% said they were willing to pay $10 or more not to have to look at the platforms; 5% said they would be willing to pay something less than $10; 32% said they would not support such a tax; 23% would not answer the question. Assuming honesty, the residents of at least this area appear to place a rather high value on their view of the ocean.

<u>The regional cost of the spill</u>.--In the long run, assuming competition, the consumer is going to bear the national costs of all spills which accrue to the oil industry and government. Most of the other national costs, the uncompensated costs, fall by nature on the region: commercial fishery losses, decrease in shoreline property values, and local recreational values. Thus, in the long run, the region will bear just about all the national cost associated with its spills. This will not be apparent in the individual spill and due to restraints on competition within the petroleum industry, it may not happen exactly. A particular region may not receive full credit for low spill cost, but there is little reason to expect a large difference between national costs of regional spills and regional costs.

On an individual spill, it appears that on the basis of the Santa Barbara study, there will be considerable compensation of certain categories of direct losses, specifically clean-up. For Santa Barbara these locally compensated losses amounted to roughly 2/3 of the total estimated cost. However, the incidence of other losses will remain where it first fell, unless regulatory or judicial procedures are changed.

Using the above rough estimate of $5.00 per gallon and combining this with the present value of our high estimate of the mean amount spilled under the various hypotheses, one can obtain a <u>very rough</u> idea of the mean loss in regional income associated with nearshore spills for the various development hypotheses. The estimates of the present value of the mean amount spilled for eight development hypotheses are given in Table I.7.2 for a regional cost of capital of 8% and two consumption growth rates.

Multiplying these figures by $5.00 per gallon leads to increases when compared to the projection of the present system (Number 1) ranging from a spill cost of $15 million to a cost of $75 million for the 2% growth rate, and from an increased loss ranging from $20 million to $110 million for the 4% growth rate.

Once again we caution that these are generally pessimistic, order of magnitude estimates. In particular, they do not allow for advances in spill prevention and control. It is difficult to say just how much can be made of these numbers. Perhaps the one firm conclusion we can draw is: it is possible that the swings in the cost of uncontrolled, nearshore spills will be of the same order of magnitude as the swings in other regional costs associated with certain of the differentials in refinery location and products distribution systems which we have examined (e.g. 65' Delaware vs. Machiasport under full employment).

In examining Table I.7.2, we must remember that other factors may mitigate the impact of the projected costs. In particular, a pipeline products distribution system which concentrates almost all the regional spill problems at one point may have some advantages from a spill control point of view in addition to the decrease in ship to shore transfers. This alternative also substitutes to a degree crude spills for products spills, which can have some biological advantages. Moreover, if we use best-case estimates of the spillage, then the very large, pipeline-serviced find generates the lowest estimates of spill cost as a result of the concomitant decrease in regional tanker traffic.

However, if these numbers are correct, the mean of additional regional spill cost associated with a tanker/barge-serviced, regional refinery exceeds the swings in regional cost due to decrease in crude and products transport expenses from moving from a deepwater Middle Atlantic refinery to such a regional refinery assuming full employment (see Chapter I.8). This is true under <u>both</u> the high and low estimates. The numbers also indicate, if true, that the region could afford to invest sizeable sums in an effective oil spill control system.

Table I.7.2

Present Value of High Estimate of Mean Amount Spilled Between 1978 and 2018 Assuming Regional Cost of Capital = 8%

Plan No.	Option	Consumption Growth Rate	
		2%	4%
1	No Find No Reg. Ref.	20 million gals.	30 million gals.
2	No Find Reg. Ref. Pres. P.D.S.	35 " "	52 " "
3	No Find Reg. Ref. Pipeline P.D.S.	23 " "	34 " "
4	Large Find No Reg. Ref.	20 " "	30 " "
5	Small Find Reg. Ref. Pres. P.D.S.	35 " "	52 " "
6	Small Find Reg. Ref. Pipeline P.D.S.	23 " "	34 " "
7	Large Find Reg. Ref. Pres. P.D.S.	35 " "	52 " "
8	Large Find Reg. Ref. Pipeline P.D.S.	23 " "	35 " "

In any event, these numbers are far larger than our estimate of the regional income effects of any other environmental impact we have studied. Clearly, in view of this and in view of the large possible range of errors, the large, nearshore spill problem deserves top priority in any further investigations.

Fiske, J., Watson, C., and Coates, P., "A Study of the Marine Resources of Pleasant Bay," Massachusetts Department of Natural Resources, Monograph Series No. 5, May 1967.

Mead, W. and Sorenson, P., "The Economic Cost of the Santa Barbara Oil Spill," Proceedings Santa Barbara Oil Symposium, December, 1970.

Chapter I.8
Results of Simulations

I.8.1 Introduction

In this chapter, the results of the computer simulations of the various development hypotheses on real regional income are presented. The basic rationale is:

1) For a given oil consumption growth rate, all the hypotheses have been designed to perform exactly the same function: supply the region the specified amounts of energy by product delivered to the products reception ports through the period 1978 to 2018.

2) For each such hypothesis, the program estimates the cost to the region of obtaining this energy, that is, the market value of the alternate consumption forgone in order to obtain these petroleum products. We have expressed this value in the equivalent amount the region would have to put up now (1972) in order to make the required payments through the future - the present value of the regional cost of the hypothesis. In computing this number, we have attempted to correct for outlays which are not costs to the region (regional public revenues, profits accruing to New Englander investors) and to price regional labor at the value of its alternate output when this appears to differ from the market wage rate.

3) Since, for a given consumption growth rate, all the hypothetical developments perform the same function, the difference in present valued regional cost between two such hypotheses is the difference in the market value of what the region can consume associated with moving from one

> hypothesis to the other expressed in equivalent amount received now. This is the change in real regional income associated with moving from one hypothesis to the other. The cheaper of the two performs the same service but leaves the region something left over, which something can be spent as the region desires.*

Following this basic line of reasoning, in this chapter we will first present our estimates of the regional cost associated with each development investigated and then examine the differentials between these regional costs to obtain the estimates of the change in real regional income associated with following one hypothesis rather than another.

It should be remembered that all regional costs discussed in this chapter do not include the swings in regional income due to environment effects discussed in the last two chapters.

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*Of course, this something left over will be unequally distributed among the region's inhabitants. Some will gain more than others and, in general, some will find the value of their market consumption decreased, although the market value of the region's consumption as a whole has increased. We have not studied the intraregional distribution of the changes in regional income. However, the computer program does break down the increase by (a) consumer, (b) regional public bodies, (c) federal taxpayer, (d) regional investor profits.

I.8.2 The no offshore petroleum cases

We will begin what is necessarily a somewhat complicated discussion by considering those development hypotheses not involving a Georges Bank petroleum discovery. For these cases, neither federal gas regulatory policy nor control of the Georges Bank is a relevant variable, leaving only the import quota and foreign crude price as policy variables.

We have investigated essentially nine combinations of shoreside refinery location policy and products distribution system. All the runs discussed in this chapter will assume residual fuel is imported. The resulting estimates of real regional cost for the four combinations of consumption growth rate and regional cost of capital are given in Tables I.8.1 through I.8.4.* These tables should not be compared with each other. For example, the lower values in the 15% runs do not mean that this situation is "cheaper" than the 8%, for they represent a different assumption with respect to a very important price, the price of capital. Each person should pick that combination of growth rate and cost of capital which to him seems most likely and make all his comparisons within that table. He can then check the sensitivity of his conclusions to this choice by making similar comparisons within the other tables.

Consider, for example, Table I.8.1 (8% cost of capital, 2% growth rate), which displays several interesting interdependences. For example, if refining capacity is based in present Delaware, the present valued loss in regional income due to the quota is $3.76 billion, assuming no escalation in foreign crude cost. However, if refinery

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*The three numbers shown for each case involving a regional refinery are regional cost assuming full employment, moderate underemployment, and extreme unemployment respectively. The regional payrolls associated with the other alternatives are so small that the effect of varying the employment assumption is insignificant.

capacity is based on a deepwater Delaware, the quota costs the region \$4.41 billion. This differential is due primarily to the fact that, without the quota, Persian Gulf oil is the marginal crude. With the quota, Louisiana oil will be the marginal crude. Persian Gulf crude can make greater advantage of the deepwater terminal than can Gulf oil. Or compare the difference between present Delaware and 65' Delaware with the quota assuming no escalation (\$130 million) with the same difference with escalation (\$680 million). This differential is due to our assumption that the marginal crude assuming no escalation is from Louisiana, while the marginal crude with escalation is from the Persian Gulf. Once again, the latter oil obtains a much greater advantage from the deep draft terminal than does the former.* Other, more subtle differences involving the indirect effects of profits and taxes can be traced.

Such niceties aside, a glance at any one of the tables indicates that the single most important variable with respect to the cost of New England oil consumption is the size of the payment to the exporting country. Swings due to this variable simply overwhelm all the other differentials. In Table I.8.1, the swing is approximately \$10 billion. If one believes that regional consumption will grow at 2%, that the region can invest its capital resources at 8%, then we estimate the difference in regional cost of its oil consumption 1978 to 2012 between rapid escalation of foreign crude costs f.o.b. and constant foreign crude costs is equivalent to handing everyone in the region \$800 now. Using 4% growth rate rather than 2%,

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*Under our assumptions, the import quota is not as expensive under foreign crude cost escalation as it is now for the consumer since the present differential in East Coast price is more than \$1.00 with and without the quota.

Table I.8.1
P.V. Regional Costs-No Offshore
8% Cost of Capital-No Resid
2% Consumption Growth Rate
(Billions of 1972 Dollars)

	Import Quota	No Import Quota
No Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	22.37	18.61
65' Delaware	22.14	17.73
Pt. Tupper	22.35	17.80
Machiasport	22.08, 21.85, 21.39	17.61, 17.38, 16.92
Off Boston SBM		
Present Delaware	22.31	18.55
65' Delaware	22.08	17.67
Pt. Tupper	22.28	17.73
Machiasport	22.03, 21.80, 21.05	17.56, 17.33, 16.86
Pipeline		
Dighton	21.77, 21.53, 21.05	17.32, 17.08, 16.60
Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	32.77	30.16
65' Delaware	31.89	29.28
Pt. Tupper	31.96	29.35
Machiasport	31.77, 31.54, 31.08	29.16, 28.93, 28.47
Off Boston SBM		
Present Delaware	32.71	30.11
65' Delaware	31.82	29.22
Pt. Tupper	31.89	29.29
Machiasport	31.72, 31.48, 31.02	29.11, 28.88, 28.42
Pipeline		
Dighton	31.48, 31.24, 30.76	28.87, 28.63, 28.16

Table I.8.2
P.V. Regional Costs-No Offshore
15% Cost of Capital-No Resid
2% Consumption Growth Rate
(Billions of 1972 Dollars)

	Import Quota	No Import Quota
No Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	8.430	7.271
65' Delaware	8.341	6.910
Pt. Tupper	8.437	6.940
Machiasport	8.311, 8.222, 8.043	6.852, 6.762, 6.583
Off Boston SBM		
Present Delaware	8.409	7.250
65' Delaware	8.320	6.889
Pt. Tupper	8.414	6.917
Machiasport	8.293, 8.203, 8.022	6.834, 6.743, 6.563
Pipeline		
Dighton	8.179, 8.085, 7.897	6.732, 6.638, 6.450
Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	12.34	11.39
65' Delaware	11.98	11.03
Pt. Tupper	12.01	11.06
Machiasport	11.92, 11.83, 11.65	10.97, 10.88, 10.70
Off Boston SBM		
Present Delaware	12.32	11.37
65' Delaware	11.96	11.01
Pt. Tupper	11.98	11.04
Machiasport	11.90, 11.81, 11.63	10.95, 10.86, 10.68
Pipeline		
Dighton	11.80, 11.71, 11.52	10.85, 10.76, 10.57

Table I.8.3
P.V. Regional Costs-No Offshore
8% Cost of Capital-No Resid
4% Consumption Growth Rate
(Billions of 1972 Dollars)

	Import Quota	No Import Quota
No Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	32.57	27.01
65' Delaware	32.20	25.69
Pt. Tupper	32.51	25.79
Machiasport	32.12, 31.81, 31.19	25.51, 25.20, 24.58
Off Boston SBM		
Present Delaware	32.48	26.92
65' Delaware	32.10	25.85
Pt. Tupper	32.39	25.67
Machiasport	32.05, 31.73, 31.11	25.43, 25.12, 24.50
Pipeline		
Dighton	31.65, 31.33, 30.69	25.08, 24.76, 24.12
Escalation of Foreigh Crude Cost		
Present Products Distribution System		
Present Delaware	48.02	44.17
65' Delaware	46.70	42.85
Pt. Tupper	46.80	42.95
Machiasport	46.53, 46.22, 45.59	42.67, 42.36, 41.74
Off Boston SBM		
Present Delaware	47.93	44.08
65' Delaware	46.60	42.74
Pt. Tupper	46.68	42.83
Machiasport	46.45, 46.14, 45.51	42.60, 42.28, 41.66
Pipeline		
Dighton	46.09, 45.77, 45.13	42.24, 41.92, 41.28

Table I.8.4
P.V. Regional Costs-No Offshore
15% Cost of Capital-No Resid
4% Consumption Growth Rate
(Billions of 1972 Dollars)

	Import Quota	No Import Quota
No Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	11.40	9.826
65' Delaware	11.26	9.324
Pt. Tupper	11.39	9.362
Machiasport	11.23, 11.11, 10.88	9.251, 9.132, 8.738
Off Boston SBM		
Present Delaware	11.37	9.796
65' Delaware	11.24	9.296
Pt. Tupper	11.36	9.331
Machiasport	11.21, 11.09, 10.85	9.085, 9.108, 8.869
Pipeline		
Dighton	11.05, 10.92, 10.68	9.085, 8.962, 8.715
Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	16.74	15.46
65' Delaware	16.24	14.95
Pt. Tupper	16.28	14.99
Machiasport	16.17, 16.05, 15.81	14.88, 14.76, 14.52
Off Boston SBM		
Present Delaware	16.71	15.43
65' Delaware	16.21	14.93
Pt. Tupper	16.25	14.96
Machiasport	16.14, 16.02, 15.78	14.86, 14.74, 14.50
Pipeline		
Dighton	16.00, 15.88, 15.63	14.72, 14.59, 14.35

increase this differential by 50%. Similar conclusions can be drawn from the other tables.*

Offshore discoveries aside, the next most important variable is the import quota. The swings associated with removing the import quota are about 40% to 25% as large as the swings associated with foreign crude pricing.

The next most important swing is that associated with moving away from dependence on shallow water refining to deep water refining. For example, going from present Delaware to 65' Delaware increases present valued regional income from $230 million to over $800 million at 2% and 8%, depending on import quota and foreign crude cost.

In general, the foreign refining option does not appear too favorable when compared with the deepwater American refining. Our analysis is biased against foreign refining on two counts:

1) We have costed products distribution assuming American flag products carriers. Under present law, these vessels could be foreign flag. This is important to Pt. Tupper because its chief disadvantage is distance to products reception ports.

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*This is not the proper occasion to enter into a discussion of imperfections in the foreign currency market. However, if the payments to the exporting country escalate, some of the decrease in U.S. national income will undoubtedly take the form of a devaluing of the U.S. dollar. Also, undoubtedly, this devaluation will be resisted for some time and be a much-publicized cause for public concern. As far as New England is concerned, this is a non-issue. Devaluation is merely a symptom of the loss in national income associated with the increased payments to the exporters and a balance of payments deficit merely a symptom of the delay in devaluing. Whatever the price of the dollar, a real income maximizing exporters' cartel, unless effectively resisted, will set crude price at the point where they obtain the maximum real product from the U.S. in return for their oil. In the long run, this real product does not depend on the exchange rate.

2) We have assumed that refining is as expensive foreign as domestic. A foreign country might be willing to suffer lower environmental standards, allowing the American consumer to transfer his environmental costs elsewhere.

However, we did not attempt to correct for these biases, on the grounds that if the foreign country were managed properly, it would make sure that its products delivered to the U.S. were as expensive as the marginal U.S. refined products by proper taxation.

With respect to the deepwater American refineries, under full employment, the deepwater Maine option is slightly superior to deepwater Delaware. Under the import quota, the differential runs from \$40 to \$120 million, being smaller if a deepwater products reception port in Boston is in existence. Without the import quota, the differential hovers around \$100 million under full employment. It is interesting to compare these numbers with those of Table I.7.2 (first column) where the difference in the present value of the mean amount spilled for these two hypotheses is estimated at 15 million gallons. At \$5.00 per gallon, our very rough estimate of the mean of the difference in spill cost is roughly equal to the increase in regional income due to decreased products prices, etc.

This assumes no increase in regional income due to employment. For the middle estimate (60% of refinery payroll goes to New Englanders, whose income is increased 1/3), this increase has a present value of \$230 million. For the extreme assumption, 60% of refinery payroll goes to New Englanders who would otherwise have nothing to do, this increase is about \$700 million.

At 2% growth rate and 8% cost of capital, the SBM terminal off Boston increases regional income according to our assumptions from \$30 to \$70 million, depending on refinery location. However, our analysis is biased in favor of the terminal in that it assumes all the region's imported resid is landed through the terminal, when in fact about 23% of this oil is handled through Boston. Since the terminal just pays for itself on the basis of distillate products (see Table I.2.13), these figures should be reduced to about $8 to $20 million. A positive present value of $10 to $20 million on a $20 million investment is still an eminently worthwhile proposition from a purely economic viewpoint.* However, it is clear that the terminal is marginal enough to require analysis at a much more detailed level. It makes no sense whatsoever if the region opts for a southeastern New England refinery policy. In general, the argument for the terminal is stronger at 4% growth rate and considerably weaker at 15% cost of capital.

The southeastern New England refinery policy - pipeline distribution option generates the lowest regional costs of all the options investigated with an estimated increase in regional income of about $300 million over 65' Delaware and deepwater Maine for 2% growth and 8% cost of capital and full employment. As indicated elsewhere, we believe our economic analysis is biased against this alternative in that we have not given it credit for any savings in secondary distribution. These could be substantial. The present differential between the landed cost of home heating oil and the price at the home is about 7-1/2¢ per gallon or $3.00 per barrel. The products pipeline could cut some tank truck hauls significantly. However, we have not investigated this issue.

Similar comparisons within Tables I.8.2, I.8.3 and I.8.4 yield similar relative results for the other combinations of growth rate and cost of capital although of course the absolute magnitudes of the differentials change. The ranking of the various refinery-products distribution systems remains unaltered.

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*At the Massport estimated cost of $34 million, the terminal is definitely marginal by our numbers. However, our analysis is simply not detailed enough to be accurate at the $10 million level.

I.8.3 The offshore cases

When we turn our attention to the hypothetical discoveries, the exposition becomes complicated by the large number of variables involved. For each possible offshore discovery, refinery location and products distribution system, we have 64 possible combinations of growth rate, cost of capital, foreign crude cost, quota policy, gas regulatory policy, and control of the Bank. Tables I.8.1 through I.8.4 indicate that our conclusions about the relative effect of the various options are insensitive to the first two variables. Pt. Tupper does not appear all that interesting and judgements about the SBM products terminal can be made independently of the offshore discovery.* Since the regional refinery generates the overwhelming proportion of the increase in regional payrolls, the same thing is true of the effect of unemployment. Hence, for the remainder of the report we will focus on a growth rate of 2%, a cost of capital of 8%, full employment, and present Delaware-present PDS, 65' Delaware-present PDS, Machiasport-present PDS, and Dighton-pipeline PDS. For each of these four refinery-products distribution system policies, we will present the results for the 15 discoveries listed in Table I.8.5. Table I.8.5 also shows the number of drilling platforms which the program indicates the investor would employ and the recoverabilities. These discoveries have been chosen to cover a spectrum of possibilities,**ranging from the minimum size discovery which would be developed up. For these runs, the secondary reservoir variables have been fixed at the values shown in Table I.8.6.

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*This is not quite true. An SBM off Boston decreases the cost of importing resid slightly, which changes the value of Georges Bank gas a little.

**We have run thousands of other cases which are available for examination.

Table I.8.5
Discoveries Investigated in Chapter I.8 Runs

	Oil In Place Billion Bbl	Gas In Place Trillion Cf	No. of Fields	Total No. of Platforms	% Rec. Oil	% Rec. Gas
Gas	.05	1	1	1	89.5	89.5
Fields	.05	3	1	6	89.5	89.5
	.05	5	5	10	89.5	89.1
	.05	10	5	20	89.5	88.9
Small	.4	.08	1	3	23.3	59.5
Oil	.4	.4	1	3	14.7	81.0
Med.	1	.2	1	10	23.3	56.5
Oil	1	1	1	10	14.7	80.1
Large	3	.6	5	15	23.3	56.6
Oil	3	3	5	15	14.7	79.6
Very	5	1	5	25	23.3	57.0
Large	5	5	5	25	14.7	79.2
Oil						
Giant	10	2	5	30	23.1	54.4
	10	10	5	30	14.7	79.3

Table I.8.6
Characteristics of Discoveries Investigated
in Chapter I.8

Vertical depth	10,000 ft	Permeability	.1 Darcys
Pressure	5,000 psi	Porosity	20%
Temperature	200°F	Connate water	30%
Pay thickness	75'	Water depth	210 ft
Oil viscosity	4.0 cp	Max deviation	45°
Gas Sp. G.	0.6	Oil API	30
Internal gas drive		No reinjection	
Oil allowable	1,000 bpd	Gas allowable	15 MMcfd
% Lease	75		
Royalty oil	45¢/bbl	Royalty gas	12.5% landed price
Max no. of platforms erected per year			5
Landed gas price under regulation			30¢/Mcf
Landed gas price - deregulation			$1.01 ↔ 62¢/Mcf

Examining Tables I.8.7 through I.8.10, it is clear that the variable of overriding importance remains the payments to the exporting nation for imported oil, even for a very large find. By the same token, a given find is more valuable to the region under foreign crude cost escalation, for the Georges Bank petroleum is displacing more costly oil in this situation.

The second thing to notice about these numbers is that the value of a given find to the region is critically dependent on

a) who controls the find;

b) if the region doesn't control the find, on whether or not natural gas prices are deregulated.

Under the situation of federal control of the Bank and deregulation of natural gas prices, even a very large find increases regional income by $200 million (no escalation) and $400 million (escalation), while a large range of finds increase regional income by less than $50 million. On the other extreme, if the region controls the Bank and gas prices are not deregulated, an extremely large find would result in net increase in region's income of over $4 billion (escalation) and $2 billion (no escalation), while the value of rather small finds ranges from $70 to $300 million. The second most favorable combination of control over the Bank and gas pricing to the region is regional control and deregulation. This is generally slightly less advantageous to the region than regulation due to the fact that the region recovers only about 75% of the additional gas profits, all of which formerly went to the consumer. However, if a very marginal gas find is involved which will not be produced under regulation, then deregulation is very

Table I.8.7
Present Valued Regional Cost of Selected Discoveries-Present Delaware
(Billions of 1972 Dollars)
Growth Rate=2% Cost of Capital=8% Full Employment Present Products Distribution System

Oil in place (billion bbl)	Gas in place (trillion cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Import Quota				No Import Quota				Import Quota				No Import Quota			
			Region		Federal		Region		Federal		Region		Federal		Region		Federal	
			Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None			22.37	22.37	22.37	22.37	18.61	18.61	18.61	18.61	32.77	32.77	32.77	32.77	30.16	30.16	30.16	30.16
.05,	1,	1	22.17	22.19	22.24	22.35	18.41	18.43	18.48	18.59	32.35	32.41	32.46	32.73	29.75	29.80	29.85	30.12
.05,	3,	1	21.67	21.75	21.92	22.31	17.91	17.99	18.16	18.55	31.43	31.61	31.72	32.65	28.83	29.01	29.11	30.05
.05,	5,	1	21.30	21.42	21.64	22.28	17.54	17.66	17.87	18.52	30.67	30.97	31.05	32.59	28.07	28.37	28.44	29.99
.05,	10,	1	20.35	20.58	20.99	22.20	16.59	16.82	17.22	18.44	28.79	29.36	29.47	32.44	26.18	26.76	26.86	29.83
.4,	.08,	1	22.35	22.34	22.37	22.37	18.58	18.58	18.60	18.60	32.65	32.64	32.75	32.75	30.05	30.03	30.15	30.15
.4,	.4,	1	22.29	22.30	22.32	22.36	18.53	18.54	18.56	18.60	32.55	32.57	32.63	32.75	29.75	29.97	30.03	30.14
1,	.2,	1	22.29	22.29	22.35	22.36	18.52	18.53	18.59	18.60	32.42	32.43	32.70	32.73	29.82	29.82	30.09	30.13
1,	1,	5	22.17	22.19	22.24	22.35	18.40	18.43	18.47	18.59	32.22	32.28	32.43	32.72	29.61	29.67	29.83	30.11
3,	.6,	5	21.98	21.98	22.29	22.33	18.22	18.22	18.53	18.57	31.71	31.73	32.57	32.66	29.11	29.12	29.96	30.05
3,	3,	5	21.67	21.72	22.01	22.31	17.90	17.96	18.25	18.54	31.14	31.29	31.87	32.62	28.54	28.68	29.27	30.01
5,	1,	5	21.69	21.70	22.25	22.30	17.92	17.93	18.48	18.54	31.05	31.07	32.45	32.59	28.44	28.47	29.85	29.98
5,	5,	5	21.28	21.37	21.81	22.27	17.52	17.61	18.05	18.51	30.24	30.47	31.38	32.53	27.64	27.86	28.77	29.93
10,	2,	5	21.10	21.11	22.16	22.24	17.34	17.35	18.40	18.48	29.82	29.86	32.27	32.46	27.21	27.25	29.66	29.85
10,	10,	5	20.27	20.42	21.43	22.18	16.51	16.66	17.67	18.41	28.27	28.63	30.48	32.34	25.66	26.03	27.88	29.77

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices
Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

Table I.8.8
Present Valued Regional Cost of Selected Discoveries-65' Delaware
(Billions of 1972 Dollars)
Growth Rate=2% Cost of Capital=8% Full Employment Present Products Distribution System

Oil in place (billion bbl)	Gas in place (trillion cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Import Quota				No Import Quota				Import Quota				No Import Quota			
			Region		Federal		Region		Federal		Region		Federal		Region		Federal	
			Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None			22.14	22.14	22.14	22.14	17.73	17.73	17.73	17.73	31.89	31.89	31.89	31.89	29.28	29.28	29.28	29.28
.05,	1,	1	21.95	21.97	22.01	22.13	17.54	17.56	17.60	17.71	31.48	31.53	31.58	31.85	28.87	28.93	28.97	29.25
.05,	3,	1	21.45	21.53	21.69	22.08	17.04	17.12	17.28	17.67	30.56	30.74	30.84	31.78	27.96	28.14	28.24	29.17
.05,	5,	1	21.08	21.20	21.41	22.05	16.67	16.79	17.00	17.64	29.80	30.10	30.17	31.72	27.19	27.49	27.57	29.11
.05,	10,	1	20.12	20.36	20.76	21.97	15.71	15,95	16.35	17.56	27.93	28.49	28.59	31.56	25.31	25.89	25.98	28.95
.4,	.08,	1	22.12	22.12	22.14	22.14	17.71	17.71	17.73	17.73	31.79	31.77	31.88	31.88	29.18	29.16	29.27	29.27
.4,	.4,	1	22.07	22.08	22.09	22.14	17.66	17.67	17.68	17.72	31.68	31.70	31.76	31.87	29.08	29.10	29.15	29.26
1,	.2,	1	22.07	22.08	22.12	22.14	17.66	17.67	17.71	17.73	31.57	31.58	31.82	31.86	28.96	28.97	29.21	29.25
1,	1,	5	21.95	21.98	22.01	22.13	17.54	17.57	17.60	17.72	31.36	31.41	31.56	31.84	28.75	28.81	28.95	29.24
3,	.6,	5	21.81	21.82	22.07	22.11	17.40	17.41	17.66	17.70	30.90	30.92	31.70	31.79	28.30	28.31	29.09	29.18
3,	3,	5	21.49	21.54	21.79	22.08	17.07	17.13	17.38	17.67	30.31	30.46	31.00	31.75	27.71	27.85	28.40	29.14
5,	1,	5	21.56	21.57	22.03	22.08	17.15	17.16	17.62	17.67	30.27	30.29	31.59	31.72	27.66	27.69	28.98	29.12
5,	5,	5	21.13	21.21	21.59	22.05	16.71	16.80	17.18	17.64	29.44	29.66	30.51	31.66	26.83	27.06	27.91	29.06
10,	2,	5	21.03	21.04	21.95	22.03	16.62	16.63	17.54	17.62	29.10	29.14	31.41	31.60	20.50	26.53	28.80	28.99
10,	10,	5	20.17	20.31	21.22	21.96	15.76	15.90	16.81	17.55	27.52	27.88	29.62	31.48	24.91	25.27	27.02	28.87

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices

Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

Table I.8.9
Present Valued Regional Cost of Selected Discoveries-Machiasport
(Billions of 1972 Dollars)
Growth Rate=2% Cost of Capital=8% Full Employment Present Products Distribution System

Oil in place (billion bbl)	Gas in place (trillion cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Import Quota				No Import Quota				Import Quota				No Import Quota			
			Region		Federal		Regional		Federal		Regional		Federal		Region		Federal	
			Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None			22.08	22.08	22.08	22.08	17.61	17.61	17.61	17.61	31.77	31.77	31.77	31.77	29.16	29.16	29.16	29.16
.05,	1,	1	21.89	21.91	21.95	22.06	17.42	17.44	17.48	17.59	31.36	31.41	31.46	31.73	28.75	28.81	28.85	29.12
.05,	3,	1	21.39	21.47	21.63	22.02	16.92	16.99	17.16	17.55	30.44	30.62	30.72	31.65	27.83	28.01	28.11	29.05
.05,	5,	5	21.02	21.14	21.35	21.99	16.54	16.67	16.87	17.52	29.68	29.98	30.05	31.59	27.07	27.37	27.44	28.98
.05,	10,	5	20.06	20.30	20.69	21.91	15.59	15.82	16.22	17.43	27.79	28.37	28.46	31.43	25.19	25.76	25.85	28.83
.4,	.08,	1	22.06	22.06	22.08	22.08	17.59	17.59	17.61	17.61	31.66	31.65	31.75	31.75	29.06	29.04	29.15	29.15
.4,	.4,	1	22.01	22.02	22.03	22.08	17.54	17.55	17.56	17.60	31.56	31.58	31.63	31.75	28.95	28.98	29.03	29.14
1,	.2,	1	22.01	22.02	22.06	22.08	17.54	17.55	17.59	17.60	31.45	31.45	31.70	31.73	28.84	28.85	29.09	29.13
1,	1,	5	21.89	21.92	21.95	22.07	17.42	17.44	17.47	17.59	31.24	31.29	31.43	31.72	28.63	28.69	28.83	29.11
3,	.6,	5	21.75	21.76	22.01	22.05	17.28	17.28	17.54	17.57	30.78	30.79	31.58	31.66	28.17	28.19	28.97	29.06
3,	3,	5	21.42	21.48	21.72	22.02	16.95	17.01	17.25	17.55	30.19	30.33	30.88	31.62	27.58	27.73	28.27	29.01
5,	1,	5	21.49	21.50	21.97	22.02	17.02	17.03	17.49	17.55	30.14	30.17	31.46	31.60	27.53	27.56	28.85	28.99
5,	5,	5	21.06	21.15	21.53	21.98	16.58	16.67	17.05	17.51	29.31	29.53	30.38	31.54	26.70	26.93	27.78	28.93
10,	2,	5	20.96	20.97	21.89	21.97	16.48	16.50	17.42	17.49	28.97	29.01	31.28	31.47	26.36	26.40	28.68	28.87
10,	10,	5	20.10	20.24	21.16	21.90	15.62	15.77	16.68	17.42	27.38	27.74	29.49	31.35	24.77	25.14	26.89	28.75

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices

Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

Table I.8.10
Present Valued Regional Cost of Selected Discoveries-Dighton
(Billions of 1972 Dollars)
Growth Rate=2% Cost of Capital=8% Full Employment Pipeline Products Distribution System

Oil in place (billion barrel)	Gas in place (trillion cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Import Quota				No Import Quota				Import Quota				No Import Quota			
			Region		Federal		Region		Federal		Region		Federal		Region		Federal	
			Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None			21.77	21.77	21.77	21.77	17.32	17.32	17.32	17.32	31.48	31.48	31.48	31.48	28.87	28.87	28.87	28.87
.05,	1,	1	21.58	21.60	21.64	21.75	17.13	17.15	17.19	17.30	31.07	31.13	31.17	31.44	28.47	28.52	28.56	28.84
.05,	3,	1	21.08	21.15	21.31	21.71	16.63	16.71	16.87	17.26	30.15	30.33	30.43	31.37	27.55	27.73	27.82	28.76
.05,	5,	5	20.70	20.83	21.03	21.68	16.26	16.38	16.58	17.23	29.39	29.69	29.76	31.30	26.78	27.08	27.15	28.70
.05,	10,	5	19.75	19.98	20.38	21.59	15.30	15.54	15.93	17.15	27.50	28.08	28.17	31.14	24.90	25.47	25.57	28.54
.4,	.08,	1	21.75	21.75	21.77	21.77	17.30	17.30	17.32	17.32	31.38	31.36	31.47	31.47	28.77	28.75	28.86	28.86
.4,	.4,	1	21.70	21.71	21.72	21.76	17.25	17.26	17.27	27.31	31.27	31.29	31.35	31.46	28.67	28.69	28.74	28.85
1,	.2,	1	21.69	21.71	21.75	21.76	17.25	17.26	17.30	17.31	31.16	31.16	31.41	31.45	28.55	28.56	28.80	28.84
1,	1,	5	21.58	21.60	21.63	21.75	17.13	17.15	17.19	17.30	30.95	31.00	31.15	31.43	28.34	28.40	28.54	28.83
3,	.6,	5	21.42	21.43	21.70	21.73	16.98	16.98	17.25	17.29	30.48	30.49	31.29	31.37	27.87	27.89	28.68	28.77
3,	3,	5	21.10	21.16	21.41	21.71	16.65	16.71	16.96	17.26	29.90	30.04	30.59	31.33	27.29	27.43	27.98	28.73
5,	1,	5	21.15	21.16	21.65	21.71	16.70	16.71	17.20	17.26	29.83	29.85	31.17	31.31	27.22	27.25	28.57	28.70
5,	5,	5	20.73	20.81	21.21	21.67	16.28	16.37	16.76	17.22	29.00	29.23	30.10	31.25	26.40	26.62	27.49	28.64
10,	2,	5																
10,	10,	5	19.76	19.90	20.84	21.58	15.31	15.45	16.39	17.14	27.07	27.43	29.21	31.07	24.46	24.82	26.60	28.46

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices

Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

slightly superior to regulation.* If the region doesn't control the Bank, then for the gas fields it makes a substantial difference whether or not gas prices are deregulated. Swings of up to $1 billion are possible in this situation with and without deregulation.

Some of these effects are demonstrated more clearly in Table I.8.11, which displays the differentials in regional income between no find and each find for 65' Delaware as a function of the policy variables. In examining Table I.8.11, one must be careful to remember that the base regional cost within each of the four heavily outlined blocks is different. Therefore, any statement based on Table I.8.11 refers to the differential due to the find itself and not, for example, whether or not foreign crude cost escalates.

Table I.8.11 demonstrates that under our assumptions the value of the find to the region is independent of whether or not there is an import quota. This is a consequence of:

a) The find does not affect the cost of the marginal unit of crude. Hence, it does not affect distillate products prices.

b) Our definition of the present import quota policy: to wit, a price support system which in the long run does not affect greatly the quantity imported.

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*Our analysis of regulation-deregulation ignores the present gas being imported into the region from other sources. If there is a large gas find, this is unimportant, because little or no such gas will continue to be imported. However, if there is a small find, the region may actually gain by deregulation, because the increase in supply of imported domestic gas more than outweighs the increase in price. For example, if domestic gas at 70¢/Mcf supplanted LNG at $1.25 per Mcf, the region would win on that unit. We have not investigated these issues. It doesn't really matter for our purposes, for the difference between regulation and deregulation only becomes large for large gas finds, in which case little or no gas would be imported into the region for some time.

Table I.8.11
Increase in Regional Income Between No Find and a Number of Selected Finds as a Function of Policy Variables
Delaware 65' Present Products Distribution System 2% Growth Rate
8% Cost of Capital (Billions of Dollars)

Oil in place (billion bbl)	Gas in place (trillion cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Import Quota				No Import Quota				Import Quota				No Import Quota			
			Region		Federal		Region		Federal		Region		Federal		Region		Federal	
			Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
.05,	1,	1	.19	.17	.13	.01	.19	.17	.13	.02	.41	.36	.31	.03	.41	.35	.31	.03
.05,	3,	1	.69	.61	.45	.06	.69	.61	.45	.06	1.33	1.15	1.05	.11	1.32	1.14	.04	.11
.05,	5,	1	1.06	.94	.73	.09	1.07	.94	.73	.09	2.09	1.79	1.72	.17	2.09	1.79	1.71	.17
.05,	10,	1	2.02	1.78	1.38	.17	2.02	1.78	1.38	.17	3.97	3.40	3.30	.33	3.97	3.39	3.30	.33
.4,	.08,	1	.02	.02	.00	.00	.02	.02	.00	.00	.10	.12	.01	.01	.10	.12	.01	.01
.4,	.4,	1	.17	.06	.05	.00	.07	.06	.05	.01	.21	.19	.13	.02	.20	.18	.13	.02
1,	.2,	1	.07	.06	.02	.00	.07	.06	.02	.00	.32	.31	.07	.03	.32	.31	.07	.03
1,	1,	5	.19	.16	.13	.01	.19	.16	.13	.01	.53	.48	.33	.05	.53	.47	.33	.04
3,	.6,	5	.33	.32	.05	.03	.33	.32	.07	.03	.99	.97	.19	.10	.98	.97	.19	.10
3,	3,	5	.65	.60	.35	.06	.66	.60	.35	.06	1.58	1.43	.89	.14	1.57	1.43	.88	.14
5,	1,	5	.58	.57	.09	.06	.58	.57	.11	.06	1.62	1.60	.30	.17	1.62	1.59	.30	.16
5,	5,	5	1.01	.93	.56	.09	1.02	.93	.55	.09	2.45	2.23	1.38	.23	2.45	2.22	1.37	.22
10,	2,	5	1.11	1.10	.19	.11	1.11	1.10	.19	.11	2.79	2.75	.48	.29	2.78	2.75	.48	.29
10,	10,	5	1.97	1.83	.92	.18	1.97	1.83	.92	.18	4.37	4.01	2.27	.41	4.37	4.01	2.26	.41

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices

Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

The argument behind (a) is reasonably clear. See Chapter I.3. However, point (b) requires a little discussion. Under our assumptions, the oil corporation(s) supplying New England have the option of landing enough imported oil to supply the region's consumption at essentially the foreign cost f.o.b. plus transportation plus tariff. Without the quota, they of course have the same option. Thus, in evaluating the additional profits which they will make from the Georges Bank oil, they will compare it with the imported oil which it will displace at their cost, which is independent of the quota. Thus, the amount they will be willing to pay in leases in turn is independent of the quota.*

The actual operation of the import quota policy is considerably more complex than we have assumed. Quota allocations are distributed among refiners according to a scale-dependent formula in the form of tickets. The import tickets are then often resold to the company which actually imports the oil. The point is that in actuality the company interested in bidding on the Bank may not have "free" access to foreign crude. Hence, he will compare Georges Bank oil with his cost of imported crude, which may be foreign crude cost f.o.b. plus transport plus tariff plus the price of an import ticket, which sum can approach the cost of the marginal unit of domestic oil. And, in fact, under competitive lease bidding, the company which would be willing to pay the most for the lease would be the company in precisely this situation. In short, from the point of view of the import quota, our assumptions lead

*The value of Georges Bank gas is independent of the quota, since we assume that it displaces resid, which doesn't come under the quota.

to a conservative estimate of the lease payment. Under the import quota as presently in operation and assuming competitive enough bidding, the actual lease bids may be up to 45¢ a barrel recoverable higher than those bids shown in Table II.8.12, which would make the value of an oil find to the region under regional control and the quota about 25% higher than we have estimated.*

However defined, the existence or non-existence of the import quota is going to have almost no effect on the pressure to explore the Bank. This is a direct consequence of Figure I.2.21, which indicates that the landed investor's cost before lease and royalties of Georges Bank crude drops very sharply to the $1.00 to 80¢ level, well below the cost of foreign crude without the quota. At most, the quota will affect the size of the lease payments. Only a complete reversal of the present bargaining strength of the exporters versus the consuming nations followed by a sharp drop in payments to the exporters plus the abolition of the import quota would take the pressure off the Bank.

Table I.8.13 demonstrates that the value to the region of a find is essentially independent of refinery location. Paradoxically, the find is slightly more valuable than no find if a present Delaware refinery policy is followed. This is because the imported oil that the Georges Bank oil is replacing is 30¢ per barrel more costly under the present draft restrictions than it would be if deepwater East Coast refining were available. A portion of this 30¢ is returned to the region in the form of increased lease payments and profits, the portion of course depending on who controls the Bank. It is slightly cheaper for the investor to land Georges Bank oil at the southeastern New England refinery, especially for very large finds for which he finds it profitable to use a pipeline. A portion of this decrease in costs is returned to the region, making the

*45¢ a barrel is roughly the present value of $1.00 per barrel produced in 1982.

Table I.8.12
Present Value Lease Payments - Selected Discoveries
(Hundreds of Millions of Dollars)

Oil in place (billion bbl)	Gas in place (trillions cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Regulate				Deregulate				Regulate				Deregulate			
			Pres Del.	65' Del.	Mach-ias.	Digh-ton	Pres Del.	65' Del.	Mach-ias.	Digh-ton	Pres Del.	65' Del.	Mach-ias.	Digh-ton	Pres Del.	65' Del.	Mach-ias.	Digh-ton
.4,	.08,	1	.00	.00	.00	.00	.07	.00	.00	.00	.84	.73	.74	.74	.97	.88	.89	.89
1,	.2,	1	.08	.00	.00	.00	.19	.00	.00	.00	2.32	2.09	2.10	2.10	2.58	2.35	2.36	2.37
.05,	1,	1	.47	.43	.42	.41	1.28	1.24	1.23	1.22	.84	.79	.78	.78	2.82	2.78	2.76	2.76
3,	.6,	1	1.93	1.32	1.36	1.48	2.18	1.57	1.61	1.74	7.62	7.00	7.04	7.16	8.24	7.63	7.67	7.79
3,	3,	5	2.26	1.82	1.84	1.90	4.39	3.95	3.97	4.03	6.32	5.87	5.90	5.95	11.70	11.26	11.29	11.35
5,	1,	5	3.69	2.76	2.81	3.08	4.08	3.16	3.20	3.47	12.59	11.67	11.71	11.98	13.57	12.65	12.69	12.96
.05,	5,	5	2.59	2.54	2.54	2.53	7.22	7.17	7.17	7.16	3.02	2.96	2.96	2.96	14.14	14.09	14.08	14.08
5,	5,	5	3.45	2.78	2.82	3.01	6.75	6.08	6.12	6.31	9.82	9.16	9.20	9.39	18.19	17.52	17.56	17.75
10,	2,	5	7.61	6.14	6.24		8.17	6.69	6.80		22.13	20.65	20.76		23.52	22.05	22.15	

Table I.8.13
Present Value Difference in Regional Income - All Four Refinery Sites
2% Growth Rate 8% Cost of Capital No Escalation
(Billions of 1972 Dollars)

Oil in place (billion bbl), Gas in place (trillion cu ft), No. of fields	Present Delaware				65' Delaware				Machiasport				Dighton			
	Region		Federal		Region		Federal		Region		Federal		Region		Federal	
	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
.4, .08, 1	.02	.03	.00	.00	.02	.02	.00	.00	.02	.02	.00	.00	.02	.02	.00	.00
1, .2, 1	.08	.08	.02	.01	.07	.06	.02	.00	.07	.06	.02	.00	.08	.06	.02	.01
.05, 1, 1	.20	.18	.13	.02	.19	.17	.13	.02	.19	.17	.13	.02	.19	.17	.13	.02
3, .6, 5	.39	.39	.08	.04	.33	.32	.07	.03	.33	.32	.07	.03	.35	.34	.07	.04
3, 3, 5	.70	.65	.36	.06	.66	.60	.35	.06	.66	.60	.36	.06	.67	.61	.36	.06
5, 1, 5	.68	.67	.12	.07	.58	.57	.11	.06	.59	.58	.11	.06	.62	.61	.12	.06
.05, 5, 1	1.07	.95	.73	.09	1.07	.94	.73	.09	1.06	.94	.73	.09	1.07	.94	.74	.09
5, 5, 5	1.09	1.00	.56	.10	1.02	.93	.55	.09	1.02	.93	.55	.10	1.04	.96	.56	.10
10, 2, 5	1.27	1.26	.21	.13	1.11	1.10	.19	.11	1.12	1.11	.19	.11				

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices

Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

Dighton location very slightly superior to the other deepwater refinery policies for the large oil find as far as the effect of the find itself is concerned.

Even if the region doesn't control the Bank, it may be able to appropriate a share of the increase in national income associated with Bank income to itself directly by proper taxation of the input to regional refineries. Chapter I.2 indicates it will cost the investor 6¢ to 8¢ per barrel more to deliver Georges Bank oil to an extraregional refinery than to southeastern New England, the exact amount depending on the quantities involved and the draft capabilities of the extraregional refinery. Similarly, it would cost the investor about 51¢ per barrel more to deliver Georges Bank oil to an extraregional refinery rather than to deepwater Maine. Thus, the region could apply a tax of just slightly less than this amount on each unit of Georges Bank oil delivered to a regional refinery and the developer would still choose to deliver the oil to the refinery. A tax of more than this amount would drive the oil elsewhere. This tax would <u>not</u> affect the market price of products because even with the tax this would not be the marginal oil. Thus, the tax revenues would be a net increase in regional income, assuming the region did not control the Bank. The approximate amounts involved are given in Table I.8.14. In general, they are not large.

It is important to realize that a tax on all oil accomplishes nothing. Putting a 15¢ per barrel tax on all oil entering the region would merely raise the price of oil 15¢, which would be a transfer from the regional consumer to the regional taxpayer and not increase regional income at all. In fact, insofar as the higher price induced consumers to forgo oil consumption which would take place at the lower price, there would be a (small) net loss in regional real income. One must apply the tax against non-marginal oil.

Table I.8.14
Present Value Oil Production and Value of Transport Savings, Regional Vs. Extraregional Refining at 8%

	PV of Oil Prod. (Million Bbl)	Machiasport Vs.Delaware (Million $)	Dighton Vs. Delaware (Million $)
.4, .08, 1	50	2.5	3.0
1, 2, 1	130	6.5	7.8
.05, 1, 1	20	1.0	1.2
3, .6, 5	329	16.5	20.0
3, 3, 5	235	10.0	14.0
5, 1, 5	515	25.0	37.0
.05, 5, 1	24	1.0	1.2
5, 5, 5	369	18.5	24.0
10, 2, 5	841	42.0	67.0
10, 10, 5	643	31.5	44.0

The principle of taxing non-marginal oil admits of broader application. One of our basic assumptions has been, if the region opts for a regional refining policy, enough regional capacity is built so that all the region's consumption (including the marginal unit) is refined within the region. Under this assumption, the marginal unit is involved, and the cost savings associated with the regional refinery have been passed on to the consumer, per our assumption of a competitive market.

In reality, even if the region opts for regional refineries, it will be some time before enough capacity is built to supply the entire region and in fact it is quite likely this will never happen. The region still may import a portion of its products, in which case the unit cost of these imported products will determine market price and the cost savings associated with regional refining will not be passed on to the consumer. The regionally refined products will no longer be on the margin. In this situation, the region can still appropriate the bulk of the cost savings associated with the regional refinery to itself by

a) generating a monopoly with respect to regional refinery locations,

b) extracting all or almost all the additional profits associated with the regional refinery to itself in the form of taxes or possibly lease payments.*

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*A refinery completely owned by regional investors or a regional public body in theory could accomplish the same thing. However, an independent refinery may have problems obtaining crude and a publicly owned refinery may have problems maintaining efficiency. We haven't investigated either of these questions. The fact that by proper taxation the region can recover the savings associated with partially refining its own oil is the principal reason why we have deemed it unnecessary to investigate partial refining options explicitly in this report.

A properly set taxation policy would not affect the market price of products, for the marginal unit is not involved.

This strategy requires that the region present a united front to prospective developers. Otherwise, bidding by the various states or municipalities for the refinery's public revenues will drive the value of these revenues down to the point where the state or municipality just breaks even and the great bulk of the savings associated with the refinery would remain with the investor. A united front would seem to require some form of compensation for those regional entities who would not end up collecting the refinery's taxes in order to induce them not to bid for these revenues. Also, provision should probably be made for dropping the tax when and if sufficient capacity becomes available so that the region is taxing the marginal unit and thus the price would drop with the abolition of the tax. Otherwise, the unnecessarily high price will induce inefficient responses by consumers.

Perhaps the most intriguing application of the idea of forming refining state cartels to tax non-marginal oil would be an agreement among all the U.S. refining states to tax imported crude at the difference between the landed crude cost and the cost of marginal domestic oil. If such a cartel could be maintained, the import quota, in its present form, would become largely a transfer from the nation's consumers to the refining states' taxpayers. The revenues which currently go to holders of import quota tickets (which would become valueless) would go to the refining states. It is interesting to ponder the political problems associated with setting up and maintaining such a cartel. They are not completely different from those facing the OPEC nations in maintaining their cartel.

Finally, we need to emphasize that in general we have taken a conservative approach to the physical characteristics of a given offshore discovery. Our costing has been generous, oil recoverabilities low due to the assumption of unaided internal gas drive together with no secondary recovery, conservative reservoir characteristics have been assumed, the allowable used may be unnecessarily low and as we have seen (Figure II.1.22) this can be a very important variable. Our valuation of the gas at approximately 60¢/Mcf is undoubtedly conservative. We have assumed lease bidders have free access to imported crude. However, we have not been at all conservative in our assumptions about how the find or development is handled by the region. In essence, in each situation we have assumed that the region drives the hardest bargain it can in that circumstance. For example, if the region is the leasor, it obtains a lion's share of the increase in national income associated with the discovery by shrewd leasing. If a regional refinery is established, we have assumed in essence that either the increase in national income associated with the refinery is passed on to the consumer or the region taxes it away from the developer. In short, we have assumed a well-informed, cohesive, well-directed administration of the region's policy toward petroleum. On record, such behavior will not come automatically.

I.8.4 Summary

Assuming for the moment a 2% consumption growth rate and an 8% regional cost of capital, the relative magnitudes of the swings in regional income associated with various hypotheses aresummarized in Table I.8.15.

Table I.8.15

	Range of Present Valued Differences in Regional Income	Equivalent Amount Received Now Per New Englander
Foreign Crude Cost	-8.5 to -10.5 billion $	(~ -$750)
Import Quota	2.6 to 4.4 billion $	(~ $300)
Offshore Find	nil to 4.3 billion $	(0 - $350)
Deepwater East Coast Refining	230 to 800 million $	($15 - $65)
Regional Refining Rather than Deep-water East Coast (full employment)	40 to 300 million $	($4 - $25)
Increase in regional income due to regional refi-nery payrolls	nil to 680 million $	(0 - $55)
SBM off Boston	0 to 20 million $	(0 - $2)

This is the equivalent amount received now associated with the difference in the cost to the region of obtaining its oil consumption from 1978 on to 2018 associated with these alternatives.* Swings in environmental cost are not included. The key assumptions are:

1) The payment to the exporting nation for crude does not depend on the form of the crude transport, refining and products distribution system;

2) The markets between the oil companies and the consumer are competitive or equivalently the region taxes away any cost saving associated

*See definition of swings below. In general, the numbers in Table I.8.5 cannot be added together.

with changes in the crude transport refining and products distribution system which would accrue to the consumer under competition.

The key determinants with respect to the above ranges are:

1) Foreign crude cost. The swing is between a continuation of present levels of payments to exporting countries and continued sharp escalation. The low end of the range ($8.5 billion) occurs when the region controls a very large find, the high end when there is no find.

2) Import quota. The swing is between present import policy and no import policy. Actual value of the swing depends on assumption about what is the marginal crude under the quota. Low change in regional income occurs when marginal crude under quota is imported oil and receiving terminal is low draft. High change occurs when marginal oil under quota is domestic crude and receiving terminal is deep draft.

3) Offshore find. Swing is with and without find. Actual value of swing depends on size and composition of find <u>and</u> whether or not the region controls the find and whether or not gas prices are decontrolled. Low change in regional income occurs when find is marginal or region doesn't control find and gas prices are deregulated. High change occurs with very large find, regional control of Bank and escalation of foreign crude cost.

4) Deepwater East Coast refinery. Swing is with the substitution of extraregional, deep draft oil terminals on East Coast capable of handling 65' draft tankers as opposed to present East Coast draft restrictions. Low change occurs

under quota if marginal crude oil is domestic oil. High change occurs without quota, marginal crude oil is distant foreign oil.

5) Regional refining policy. Swing is with substitution of regional refining for dependence on deepwater extraregional refining. Low change occurs when regional refining is concentrated in deepwater Maine using present products distribution system. High change occurs when regional refining capacity is concentrated in southeastern New England employing pipeline distribution of products.

6) Effect of additional regional payrolls. Swing is with the substitution of regional refining for extraregional refining. Low change (nil) occurs under full employment. High change ($600 million) occurs when regional employees of regional refineries would have no other employment opportunities.

7) Offshore Boston products terminal. Swing is with substitution of a products terminal off Boston with 65' draft capability for present shoreside facilities. Low change occurs under southeastern New England refining policy or high estimates of terminal costs. High change occurs under deepwater extraregional refining policies and low estimates of terminal costs. However, we do not believe that our results are accurate to the ten million dollar level.

Similar swings are observed, <u>relatively speaking</u>, under other assumptions about consumption growth rate and regional cost of capital as demonstrated by Table I.8.16.

Finally, it would be consistent with our monotonous emphasis on the <u>net</u> effect on regional income to stress

Table 1.8.16
Range of Differentials in Present Valued Regional Income Associated With Alternative Values of Various Key Variables
(Billions of 1972 Dollars)

Change in Hypothesis	Cons.Growth Rate=2% Cost of Cap.=8%		Cons.Growth Rate=4% Cost of Cap.=8%		Cons.Growth Rate=2% Cost of Cap.=15%		Cons.Growth Rate=4% Cost of Cap.=15%	
	Low Change	High Change	Low Change	High Change	Low Change	High Change	Low Change	High Change
From Present Foreign Crude Payments To Escalated Crude Payments	-8.5	-10	-13.5	-17	-3.4	-4.1	-4.5	-5.6
From Import Quota To No Import Quota	+2.6	+ 4.4	+ 3.9	+ 6.6	+1.0	+1.4	+1.4	+2.3
From No Georges Bank Find To Find	nil	+ 4.3	nil	+ 4.3	nil	+2.2	nil	+2.2
From Shallow Water Extraregional Refining To Deepwater Extraregional Refining	+ .2	+ .8	+ .3	+ 2.3	+ .09	+ .36	+ .14	+ .5
From Deepwater Extraregional Refining To Deepwater Regional Refining (Full Employment)	+ .04	+ .3	+ .08	+ .6	+ .06	+ .18	+ .03	+ .24
<u>Employment Effect</u>								
From No Regional Refining To All Regional Refining	nil	+ .7	nil	+ .9	nil	+ .27	nil	+ .35

Note: See copy for circumstances leading to low and high values of differentials. In general, numbers in same column cannot be added. Numbers for different combinations of cost of capital cannot be compared.
Does not include environmental swings.

for the last time that the numbers in Table I.8.16 are our estimates of the change in the market value of the region's consumption after all the adding and subtracting has taken place, expressed in terms of equivalent amount received now. They are not to be confused with "gross effect on region's economy", "increase in regional economic activity", "revenues and payrolls generated by..." and other concepts beloved of developers and expansionist public agencies. These numbers, to the best of our ability, represent the net change in the region's wealth associated with the alternative hypotheses about the future as valued by the market. As such, we believe they deserve some contemplation.